ARCH COAL INC
Form 10-K
February 29, 2008

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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, 2007

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
	Chicago 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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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 29, 2007 was approximately $5.0 billion.

On February 25, 2008, 143,954,798 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 24, 2008 are incorporated by reference into Part III of this Form 10-K.

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Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
Subsidiaries
Consent of Ernst & Young LLP
Power of Attorney
Certification
Certification
Certification
Certification

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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 anticipates, believes, could, estimates, expects, intends, may, plans, predicts, should, will or other comparable words and phrases. Forward-looking statements by their nature address matters that are, to different degrees, uncertain. We believe that the factors that could cause our actual results to differ materially include the factors that we describe under the heading Risk Factors beginning on page 23. Those risks and uncertainties include but are not limited to the following:

- market demand for coal and electricity;
- geologic conditions, weather and other inherent risks of coal mining that are beyond our control;
- availability and price of mining and other industrial supplies;
- availability of skilled employees and other workforce factors;
- disruptions in the quantities of coal produced by our contract mine operators;
- our ability to acquire or develop coal reserves in an economically feasible manner;
- defects in title or the loss of a leasehold interest;
- railroad, barge, truck and other transportation performance and costs;
- our ability to successfully integrate the operations that we acquire;
- our ability to secure new coal supply arrangements or to renew existing coal supply arrangements;
- our relationships with, and other conditions affecting, our customers;
- our ability to service our outstanding indebtedness;
- our ability to comply with the restrictions imposed by our credit facility and other financing arrangements;
- the availability and cost of surety bonds;
- failure by Magnum Coal Company, which we refer to as Magnum, to satisfy certain below-market contracts that we guarantee;
- terrorist attacks, military action or war;
- environmental laws, including those directly affecting our coal mining operations and those affecting our customers coal usage;
- our ability to obtain and renew mining permits;

- future legislation and changes in regulations, governmental policies and taxes, including those aimed at reducing emissions of elements such as mercury, sulfur dioxides, nitrogen oxides, particular matter or greenhouse gases;

- the accuracy of our estimates of reclamation and other mine closure obligations;

- the existence of hazardous substances or other environmental contamination on property owned or used by us; and

- the availability of future permits authorizing the disposition of certain mining waste.

These factors should not be construed as exhaustive and should be read in conjunction with the other cautionary statements included in this document. These risks and 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.

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Glossary of Selected Mining Terms

Certain terms that we use in this document 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.

Assigned reserves	Recoverable 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 Btus, 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 surface mining 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, generally employing two rotating drums 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 Btus.
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.

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Reserves	That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.
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 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, 2007, we operated 18 active mines located in each of the major low-sulfur coal-producing regions of the United States. Federal and state environmental regulations affect the demand for certain types of coal by limiting the amount of sulfur dioxide that may be emitted as a result of combustion. Due to these regulations, we believe demand for low-sulfur coal exceeds demand for other types of coal. Consequently, we focus on mining, processing and marketing coal with low sulfur content. At December 31, 2007, we estimate that our proven and probable coal reserves had an average heat value of approximately 10,000 Btus and an average sulfur content of approximately 0.71%. As such, we estimate that approximately 75.4% of our proven and probable coal reserves consists of compliance coal.

We sell substantially all of our coal to power plants, steel mills and industrial facilities. For the year ended December 31, 2007, we sold approximately 135.0 million tons of coal, including approximately 8.6 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-fueled power plants in the United States. The following chart shows the breakdown of our coal production by region for 2007, expressed as a percentage of the total tons we produced:

2007 Coal Production, by Region

% of Total Tons

In 2007, we sold approximately 73.6% of our coal under contracts with a term of more than one year. At December 31, 2007, the average volume-weighted remaining term of our long-term contracts was approximately 3.8 years, with remaining terms ranging from one to ten years. At December 31, 2007, we had a sales backlog, including a backlog subject to price reopener or extension provisions, of approximately 377.5 million tons.

We believe that rapid economic expansion in developing nations, particularly China and India, has increased global demand for coal. We expect coal exports from the United States to increase in response to growing global coal demand, particularly as some of the traditional coal export nations experience mine, port, rail and labor challenges. We estimate that higher domestic demand for coal and higher U.S. coal exports will positively influence domestic coal demand. Additionally, we expect decreased production, particularly in the Central Appalachian region of the United States, to adversely impact domestic coal supply in the coming years. We anticipate continuing demand growth and weaker coal supplies 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, 2007, our expected unpriced production approximated 15 million to 25 million tons in 2008, 85 million to 95 million tons in 2009 and 95 million to 105 million tons in 2010.

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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 Inc. 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 mine in Colorado and a 65% interest in Canyon Fuel Company, which operates three mines in Utah. In October 1998, 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 acquired 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.

In December 2005, we sold the stock of Hobet Mining, Inc., Apogee Coal Company and Catenary Coal Company and their four associated mining complexes (Hobet 21, Arch of West Virginia, Samples and Campbells Creek) and approximately 455.0 million tons of coal reserves in Central Appalachia to Magnum.

The Coal Industry

Global Coal Supply and Demand. Because of its availability, stability and affordability, coal is a major contributor to the global energy supply, providing approximately 40% of the world s electricity, according to the World Coal Institute, which we refer to as the WCI. Coal is also used in producing approximately 64% of the world s steel supply, according to the WCI. Coal reserves can be found in almost every country in the world, and approximately 50 countries are currently mining coal.

Coal is traded worldwide and can be transported to demand centers by ship and by rail. Worldwide coal production approximated 5.9 billion tons in 2006 and 5.4 billion tons in 2005, according to the WCI. China produces more coal than any other country in the world. Historically, Australia has been the world s largest coal exporter, exporting more than 200 million tons in each of the last three years, according to the WCI. China, Indonesia and South Africa have also historically been significant exporters in the global coal markets, however, growing demand in China has resulted in declining coal exports and increasing coal imports. These trends have caused China to become a less significant seaborne coal supply source. In 2007, coal supply from other regions was similarly affected because of mine disruptions, train derailments and port congestion.

Growing demand for coal for power generation in many Asian countries has begun to strain global coal supplies. Seaborne coal trade increased 4.6% to approximately 806.9 million metric tons in 2007, according to SSY Consultancy & Research, Ltd. Seaborne trade into Asia increased approximately 9.1%, while European trade decreased approximately 4.3%. Demand in China is expected to grow rapidly, as the demand for electricity and the need for steel used in construction and automobile production increase.

U.S. Coal Consumption. In the United States, coal is used primarily by power plants 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 1.2 billion tons in 2007, based on information provided by the Energy Information Administration, which we refer to as the EIA.

Throughout the United States, coal has long been favored as a fuel to produce electricity because of its cost advantage and its availability. Since 1970, the use of coal to generate electricity in the United States has nearly tripled in response to growing electricity demand. According to the EIA, coal accounted for approximately 50% of U.S. electricity generation in 2007 and is projected to account for approximately 55% in 2030. By comparison, generation from natural gas is expected to peak at approximately 21% in 2018 before slowly

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declining. The following chart shows U.S. electricity generation by fuel source from 1980 through 2007 and the projected generation through 2030:

Electricity Generation by Fuel, 1980-2030
(in billion kilowatthours)

Source: EIA

According to the National Mining Association, which we refer to as the NMA, coal is the lowest-cost fossil fuel used in producing electricity. We estimate that the cost of generating electricity from coal is less than one-third of the cost of generating electricity from other fuels. According to the EIA, the average delivered cost of coal to electric power generators during the first ten months of 2007 was $1.77 /mm Btus, which was $6.39 /mm Btus less expensive than residual fuel oil and $5.28 /mm Btus less expensive than natural gas.

The EIA projects that power plants will increase their demand for coal as demand for electricity increases. The EIA estimates that electricity demand will increase by at least 40% by 2030, despite continuing efforts throughout the United States to become more energy efficient. Coal consumption has generally grown at the pace of electricity growth because coal-fueled electricity generation is used in most cases to meet baseload requirements. We estimate that coal consumption for power generation increased approximately 1.7% in 2007 as a result of average economic growth and more favorable weather than in 2006. Historically, demand for electricity has generally grown in proportion to U.S. economic growth, as measured by gross domestic product. In 2007, real gross domestic product increased 2.2%, according to the U.S. Department of Commerce.

Demand for coal is broadly influenced by weather. Weather patterns requiring greater use of air-conditioning or heating translate into greater demand for coal-based electricity generation. According to the EIA, coal stockpiles at power plants represented an approximate 53-day supply at the end of 2007, compared to coal stockpiles representing an approximate 50-day supply at the end of 2006. We believe that some domestic power plants seek to protect against future supply disruptions by maintaining higher stockpile levels.

We believe that demand growth from new coal-fueled power plants represents an important element to the long-term outlook for coal. We estimate that roughly 25 gigawatts of new domestic coal-fueled electricity generation capacity is currently under construction or in advanced permitting stages, equating to more than 85 million tons of new incremental annual coal demand, based on information obtained from the National Energy Technology Laboratory, which we refer to as the NETL, and our internal estimates. We expect all or a significant majority of these plants to be built over the next five years. The NETL also estimates that, at

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December 31, 2007, approximately 17 gigawatts of generating capacity was under construction or in advanced stages of development in 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 mercury, sulfur dioxide, nitrogen oxide and particulate matter will be introduced into the power generation industry. We believe these technological advancements will help coal retain its role as a key fuel for electric power generation well into the future.

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. As such, the price offered by steel makers for metallurgical coal is generally higher than the price offered by power plants and industrial users for steam coal. Rapid economic expansion in China, India and other parts of southeast Asia has significantly increased the demand for steel in recent years.

Prices for oil and natural gas in the United States have reached record levels because of increasing demand and tensions regarding international supply. Historically high oil and gas prices and global energy security concerns have increased government and private sector interest in converting coal into liquid fuel, a process known as liquefaction. Liquid fuel produced from coal can be refined further to produce transportation fuels, such as low-sulfur diesel fuel, gasoline and other oil products, such as plastics and solvents. Several coal-to-liquids projects are in the process of development, including a coal-to-liquids facility proposed by a coal-conversion company in which we own an equity interest. We also expect advances in technologies designed to convert coal into electricity through coal gasification processes and to capture and sequester carbon dioxide emissions from electricity generation and other sources. These technologies have garnered greater attention in recent years due to developing concerns about the impact of carbon dioxide on the global climate. 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. The United States produces approximately one-fifth of the world s coal production and is the second largest coal producer in the world, exceeded only by China. Coal in the United States represents approximately 94% of the domestic fossil energy reserves with over 250 billion tons of recoverable coal, according to the U.S. Geological Survey. The U.S. Department of Energy estimates that current domestic recoverable coal reserves could supply enough electricity to satisfy domestic demand for more than 200 years. Coal production in the United States has increased from 434 million tons in 1960 to approximately 1.2 billion tons in 2007 based on information provided by EIA.

Western region The western region includes, among other areas, 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. In addition, 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 some existing coal plants to accommodate lower Btu coal. The Western Bituminous region includes western Colorado, eastern Utah and southern Wyoming. 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 618.3 million tons in 2007 as regulations limiting sulfur dioxide emissions have increased demand for low-sulfur coal over this period.

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

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tons in 1994 to 379.6 million tons in 2007, primarily as a result of the depletion of economically attractive reserves, permitting issues and increasing costs of production.

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. We anticipate that Illinois basin coal will play an increasingly vital role in the U.S. 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 150.2 million tons in 2007.

U.S. Coal Exports and Imports. Coal exports decreased from 71.4 million tons in 1994 to 58.6 million tons in 2007. As discussed above, as global consumption for coal has increased in recent years, countries such as China, Indonesia, South Africa and Russia have decided to retain a greater percentage of their coal production for domestic consumption. This development, together with port congestion in Australia, historically the largest coal exporter in the world, and a weak U.S. dollar, has caused U.S. coal to become more attractive in global markets. We expect this trend to continue as global coal consumption continues to increase.

Historically, coal imported from abroad has represented a negligible share of total U.S. coal consumption. According to the EIA, coal imports increased from 8.9 million tons in 1994 to 36.3 million tons in 2007. Coal is imported into the United States primarily from Colombia, Indonesia 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 expect coal imports into the United States to decrease due to increasing demand in Europe.

Coal Mining Methods

The geological characteristics of our coal reserves largely determine the coal mining method we employ. We use 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 9. In 2007, approximately 80% of the coal that we produced 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 loadout facility. We reclaim disturbed areas as part of our normal mining activities. After final coal removal, 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.

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The following diagram illustrates a typical dragline 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 9. In 2007, approximately 20% of the coal that we produced 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 using mechanical shearers to extract coal from long rectangular blocks of medium to thick seams. Ultimate seam recovery using longwall mining techniques can exceed 75%. In longwall mining, we use continuous miners to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. 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 2007, approximately 17% of the coal that we produced came from underground mining operations generally using longwall mining techniques.

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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 miners to cut the coal 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, coal is mined from the pillars as workers retreat. As retreat mining occurs, the roof is allowed to collapse in a controlled fashion. Once we finish mining in an area, we generally abandon that area and seal it from the rest of the mine. In 2007, approximately 3% of the coal that we produced came from underground mining operations generally using room-and-pillar mining techniques.

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

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Coal Preparation. Coal extracted from the ground, particularly at our underground mining operations, contains impurities, such as rock, shale and clay, and occurs in a wide range of particle sizes. 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 2007, our preparation plants processed approximately 83% of the raw coal we produced in the Central Appalachia region. For more information about our preparation plants, you should see the section entitled Our Mining Operations below.

The treatments we employ depend on the properties of the extracted coal and its intended use. To remove impurities, we crush raw coal and classify it into various sizes. For the largest size fractions, we use dense media vessel 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 shale. We treat intermediate sized particles with dense medium cyclones, in which a liquid is spun at high speeds to separate coal from rock. Fine coal is treated in spirals, in which the differences in density between coal and rock allow them, when suspended in water, to be separated. Ultra fine coal is recovered in column flotation cells utilizing the differences in surface chemistry between coal and rock. By injecting stable air bubbles through a suspension of ultra fine coal and rock, the coal particles adhere to the bubbles and rise to the surface of the column where they are removed. To minimize the moisture content in coal, we may process certain coal through a centrifuge. A centrifuge spins coal very quickly, causing water accompanying the coal to separate.

Our Mining Operations

At December 31, 2007, we operated 18 active mines at 11 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:

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The following table provides a summary of information regarding our mining complexes at December 31, 2007, the total sales associated with these complexes for the years ended December 31, 2005, 2006 and 2007 and the total reserves associated with these complexes at December 31, 2007. The amount disclosed below for the total cost of property, plant and equipment of each mining complex does not include the costs of the coal reserves that we have assigned to an individual complex:

Mining Complex	Captive Mines(1)	Contract Mines(1)	Mining Equipment	Railroad	Tons Sold(2) 2005	2006	2007	Total Cost of Property, Plant and Equipment at December 31, 2007 ($ in millions)	Assigned Reserves (Million tons)
						(Million tons)			
Powder River Basin:									
Black Thunder	S		D, S	UP/BN	87.6	92.5	86.2	$ 598.8	1,314.6
Coal Creek(3)	S		D, S	UP/BN		3.1	10.2	143.0	214.4
Western Bituminous:									
Arch of Wyoming(4)				UP				24.5	19.6
Dugout Canyon	U		LW, C	UP	4.9	4.2	4.0	122.0	29.0
Skyline(3)	U		LW, C	UP		1.5	2.4	154.2	22.8
Sufco	U		LW, C	UP	7.5	7.4	6.7	229.0	51.3
West Elk	U		LW, C	UP	5.9	5.0	6.2	253.8	78.8
Central Appalachia:									
Coal-Mac	S	U	L, E	NS/CSX	3.2	3.7	3.9	141.1	30.9
Cumberland River	S(2), U(3)	U	L, C, HW	NS	2.3	2.6	2.4	122.6	21.0
Lone Mountain	U(3)		C	NS/CSX	2.6	2.5	2.4	167.1	34.7
Mountain Laurel	U		LW, C	CSX			1.0	399.1	83.0
Totals					114.0	122.5	125.4	$ 2,355.2	1,900.1

S = Surface mine
U = Underground mine

D = Dragline
L = Loader/truck

S = Shovel/truck
E = Excavator/truck
LW = Longwall
C = Continuous miner
HW = Highwall miner

UP = Union Pacific Railroad
CSX = CSX Transportation
BN = Burlington Northern Santa Fe Railway
NS = Norfolk Southern Railroad

(1)

Amounts in parentheses indicate the number of captive and contract mines at the mining complex at December 31, 2007. Captive mines are mines that we own and operate on land owned or leased by us. Contract mines are mines that 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 0.2 million tons in 2007, 1.7 million tons in 2006 and 2.2 million tons in 2005. 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. Tons of coal sold that we purchased from third parties but did not process through our loadout facilities approximated 8.4 million tons in 2007, 8.5 million tons in 2006 and 8.8 million tons in 2005.

In December 2005, we sold 100% of the stock of Hobet Mining, Inc., 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. In June 2007, we sold the Mingo Logan-Ben Creek mining complex and associated reserves to Alpha Natural Resources. We have not included any information in the table above related to those complexes. Those complexes sold 1.2 million tons in 2007, 4.0 million tons in 2006 and 17.4 million tons in 2005.

(3) In 2006, we resumed mining at our Coal Creek and Skyline complexes. We had idled the Coal Creek complex in 2000 and the Skyline complex in 2004.

(4) The inactive surface mines at the Arch of Wyoming complex are in the final process of reclamation and bond release.

Powder River Basin. Our operations in the Powder River Basin are located in Wyoming and include two surface mining complexes. During 2007, these complexes sold approximately 96.4 million tons of compliance coal. We control approximately 1.8 billion tons of proven and probable coal reserves in the Powder River Basin.

Black Thunder	Black Thunder is a surface mining complex located on approximately 24,300 acres in Campbell County, Wyoming. We control a significant portion of the coal reserves through federal and state leases. The complex currently consists of six active pit areas, one owned loadout facility and one leased loadout facility. We ship all of the coal raw to our customers via the Burlington Northern Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. Each of the loadout facilities can load a 15,000-ton train in less than three hours.
Coal Creek	Coal Creek is a surface mining complex located on approximately 7,400 acres in Campbell County, Wyoming. We control a significant portion of the coal reserves through federal and state leases. The complex currently consists of two active pit areas and a loadout facility. We ship all of the coal raw to our customers via the Burlington Northern Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. The loadout facility can load a 15,000-ton 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 mining complexes and one surface mining complex that includes four inactive surface mines. During 2007, the mining complexes in the Western Bituminous region sold approximately 19.3 million tons of compliance coal. We control approximately 459.9 million tons of proven and probable coal reserves in the Western Bituminous region.

Arch of Wyoming	Arch of Wyoming is a surface mining complex located in Carbon County, Wyoming. The complex currently consists of four inactive surface mines located on approximately 29,900 acres that are in the final process of reclamation and bond release. In 2006, we began preliminary development of a new mining area located on approximately 30,100 acres. We control a significant portion of the coal reserves associated with this complex through federal, state and private leases. During 2007, we produced a minimal amount of coal attributable to the development of the new mining area.
Dugout Canyon	Dugout Canyon mine is an underground mining complex located on approximately 18,200 acres in Carbon County, Utah. We control a significant portion of the coal reserves through federal and state leases. The complex currently consists of a longwall, two continuous miner sections and a truck loadout facility. We ship all of the coal to our customers via the Union Pacific railroad or by highway trucks. We wash a portion of the coal we produce at a 400-ton-per-hour preparation plant. The loadout facility can load approximately 20,000 tons of coal per day into highway trucks. Coal shipped by rail is loaded through a third-party facility capable of loading an 11,000-ton train in less than three hours.

Skyline	Skyline is an underground mining complex located on approximately 12,400 acres in Carbon and Emery Counties, Utah. We control a significant portion of the coal reserves through federal leases and smaller portions through county and private leases. The complex

	currently consists of a longwall, a continuous miner section and a loadout facility. We ship all of the coal raw to our customers via the Union Pacific railroad or by highway trucks. We do not process the coal mined at this complex. The loadout facility can load a 12,000-ton train in less than four hours.
Sufco	Sufco is an underground mining complex located on approximately 25,200 acres in Sevier County, Utah. We control a significant portion of the coal reserves through federal and state leases. The complex currently consists of a longwall, three continuous miner sections and a loadout facility located approximately 80 miles from the mine. We ship all of the coal raw to our customers via the Union Pacific railroad or by highway trucks. We do not process the coal mined at this complex. The loadout facility can load an 11,000-ton train in less than three hours.
West Elk	West Elk is an underground mining complex located on approximately 17,900 acres in Gunnison County, Colorado. We control a significant portion of the coal reserves through federal and state leases. The complex currently consists of a longwall, three continuous miner sections and a loadout facility. We ship all of the coal raw to our customers via the Union Pacific railroad. We do not process the coal mined at this complex. The loadout facility can load an 11,000-ton train in less than three hours.

Central Appalachia. Our operations in the Central Appalachia region are located in southern West Virginia, eastern Kentucky and southwestern Virginia and include four mining complexes comprised of nine underground mines and three surface mines. During 2007, these operations sold approximately 9.7 million tons of low-sulfur coal. Metallurgical coal accounted for 1.7 million tons of total coal sales from these operations in 2007. We control approximately 338.0 million tons of proven and probable coal reserves in Central Appalachia.

Coal-Mac	Coal-Mac is a surface and underground mining complex located on approximately 46,800 acres in Logan and Mingo Counties, West Virginia. We control a significant portion of the coal reserves through private leases. The complex currently consists of two surface mines (one captive and one contract), one contract underground mine, a preparation plant and two loadout facilities, which we refer to as Holden 22 and Ragland. We ship coal trucked to the Ragland loadout facility directly to our customers via the Norfolk Southern railroad. The Ragland loadout facility can load a 15,000-ton train in less than four hours. We ship coal trucked to the Holden 22 loadout facility directly to our customers via the CSX railroad. We wash a portion of the coal transported to the Holden 22 loadout facility at an adjacent 600-ton-per-hour preparation plant. The Holden 22 loadout facility can load a 12,000-ton train in less than four hours.
Cumberland River	Cumberland River is an underground and surface mining complex located on approximately 16,700 acres in Wise County, Virginia and Letcher County, Kentucky. We control a significant portion of the coal reserves through private leases. The complex currently consists of four underground mines (three captive, one contract) operating a total of five continuous miner sections, two captive surface operations, two highwall

miners (one captive, one contract), a preparation plant and a loadout facility. We ship approximately one-third of the coal raw to our customers via the Norfolk Southern railroad. We

	process the remaining two-thirds of the coal through a 500-ton-per-hour preparation plant before shipping it to our customers via the Norfolk Southern railroad. The loadout facility can load a 12,500-ton train in less than four hours.
Lone Mountain	Lone Mountain complex is an underground mining complex located on approximately 21,400 acres in Harlan County, Kentucky and Lee County, Virginia. We control a significant portion of the coal reserves through private leases. The complex currently consists of three underground mines operating a total of seven continuous miner sections. We convey coal mined in Kentucky to Virginia before we process it through a 1,200-ton-per-hour preparation plant. We then ship the coal to our customers via the Norfolk Southern or CSX railroad. The loadout facility can load a 12,500-ton unit train in less than four hours.
Mountain Laurel	Mountain Laurel is an underground mining complex located on approximately 30,000 acres in Logan County, West Virginia. In 2007, we began preliminary development of a new surface mining area adjacent to our underground mine. We control a significant portion of the coal reserves through private leases. The complex currently consists of a longwall, four continuous miner sections, a preparation plant and a loadout facility. We process all of the coal through a 2,100-ton-per-hour preparation plant before shipping the coal to our customers via the CSX railroad. The loadout facility can load a 15,000-ton 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, 2007, 2006 and 2005 contained in Note 22 Segment Information to our consolidated financial statements beginning on page F-1.

Transportation

We ship our coal to customers by means of railroad, barges or trucks, or a combination of these means of transportation. We also ship our coal to Atlantic coast terminals or terminals along the Gulf of Mexico for transportation to domestic and international customers. As is customary in the industry, once the coal is loaded onto the rail car, barge, truck or vessel, 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 and trucks 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 for shipment on the inland waterways.

In addition, we 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 along the Atlantic coast of the United States.

Sales, Marketing and Customers

Coal prices are influenced by a number of factors and vary dramatically by region. As a result of these regional characteristics, prices of coal 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 for certain of our Central Appalachia mines, is generally more expensive than surface mining, which is the mining method we use in the Powder River Basin and 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, we assign contract shipments to one or more mining complexes within a region capable of sourcing that coal.

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 2007, we sold approximately 73.6% of our coal under long-term supply arrangements. At December 31, 2007, the average volume-weighted remaining term of our long-term contracts was approximately 3.8 years, with remaining terms ranging from one to ten 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., Magnum Coal Company, Massey Energy Company, Patriot Coal Corporation, Peabody Energy Corp. and Rio Tinto Energy North America. Some of these coal producers are larger than we are 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 also compete with companies that produce coal from one or more foreign countries, such as Colombia, Indonesia 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 relating to these alternative fuels, such as safety and environmental considerations, affect the overall demand for coal as a fuel.

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Geographic Data

We market our coal principally to power plants, steel mills and industrial facilities located in the United States. Coal sales to foreign customers approximated $196.7 million for 2007, $162.5 million for 2006 and $166.0 million for 2005.

Safety and Environmental Regulations

Our operations, like operations of other coal companies, are subject to regulation, primarily by federal and state authorities, on matters such as: air quality standards; reclamation and restoration activities involving our mining properties; mine permits and other licensing requirements; water pollution; employee health and safety; the discharge of materials into the environment; management of materials generated by mining operations; storage of petroleum products; protection of wetlands and endangered plant and wildlife protection. Many of these regulations require registration, permitting, compliance, monitoring and self-reporting and may impose civil and criminal penalties for non-compliance.

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 over time. The possibility exists that new legislation or regulations may be adopted or that the enforcement of existing laws could become more stringent, causing coal to become a less attractive fuel source and reducing the percentage of electricity generated from coal. Future legislation or regulation or more stringent enforcement of existing laws may have a significant impact on our mining operations or our customers ability to use coal.

While it is not possible to accurately 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 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 business:

Clean Air Act. The federal Clean Air Act and similar state and local laws that regulate air emissions affect coal mining directly and indirectly. Direct impacts on coal mining and processing operations include Clean Air Act permitting requirements and/or emissions control requirements relating to particulate matter which may include controlling fugitive dust. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the emissions of fine particulate matter measuring 2.5 micrometers in diameter or smaller, sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fueled power plants and industrial boilers, which are the largest end-users of our coal. Continued tightening of the already stringent regulation of emissions and regulation of additional emissions such as carbon dioxide or other greenhouse gases from coal-fueled power plants and industrial boilers could eventually reduce the demand for coal.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

> *Acid Rain.* Title IV of the Clean Air Act imposes a two-phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and applies to all coal-fueled power plants with a capacity of more than 25-megawatts. Generally, the affected power plants have sought to comply with these requirements by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or

purchasing or trading sulfur dioxide emissions allowances. Although we cannot accurately predict the future effect of this Clean Air Act provision on our operations, we believe that implementation of Phase II has resulted in, and will continue to result in, an upward pressure on the price of lower sulfur coals as coal-fueled power plants continue to comply with the more stringent restrictions of Title IV.

Fine Particulate Matter. The Clean Air Act requires the U.S. Environmental Protection Agency, which we refer to as EPA, to set national ambient air quality standards, which we refer to as NAAQS, for certain pollutants associated with the combustion of coal, including sulfur dioxide, particulate matter, nitrogen oxides and ozone. Areas that are not in compliance with these standards, referred to as non-attainment areas, must take steps to reduce emissions levels. For example, NAAQS currently exist for particulate matter measuring 10 micrometers in diameter or smaller (PM10) and for fine particulate matter measuring 2.5 micrometers in diameter or smaller (PM2.5). The EPA designated all or part of 225 counties in 20 states as well as the District of Columbia as non-attainment areas with respect to the PM2.5 NAAQS. Those designations have been challenged. Individual states must identify the sources of emissions and develop emission reduction plans. These plans may be state-specific or regional in scope. Under the Clean Air Act, individual states have up to twelve years from the date of designation to secure emissions reductions from sources contributing to the problem. Future regulation and enforcement of the new PM2.5 standard will affect many power plants, especially coal-fueled power plants, and all plants in non-attainment areas.

Ozone. Significant additional emission control expenditures will be required at coal-fueled power plants to meet the current NAAQS for ozone. Nitrogen oxides, which are a byproduct of coal combustion, are classified as an ozone precursor. As a result, emissions control requirements for new and expanded coal-fueled power plants and industrial boilers will continue to become more demanding in the years ahead. For example, in 2004, the EPA designated counties in 32 states as non-attainment areas under the new standard. These states had until June 2007 to develop plans, referred to as state implementation plans, or SIPs, for pollution control measures that allow them to comply with the standards. The EPA described the action that states must take to reduce ground-level ozone in a final rule promulgated in November 2005. The rule is subject to judicial challenge, however, making its impact difficult to assess. In July 2007, the EPA proposed to make the current standard more stringent. If the EPA s current rules are upheld and the EPA finalizes a more stringent ozone NAAQS, additional emission control expenditures will likely be required at coal-fueled power plants.

NOx SIP Call. The NOx SIP Call program was established by the EPA in October 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said that they could not meet federal air quality standards because of migrating pollution. The program is designed to reduce nitrous oxide emissions by one million tons per year in 22 eastern states and the District of Columbia. Phase II reductions were required by May 2007. As a result of the program, many power plants have been or will be required to install additional emission control measures, such as selective catalytic reduction devices. Installation of additional emission control measures will make it more costly to operate coal-fueled power plants, thereby making coal a less attractive fuel.

Clean Air Interstate Rule. The EPA finalized the Clean Air Interstate Rule, which we refer to as CAIR, in March 2005. CAIR calls for power plants in 29 eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide. The rule requires states to regulate power plants under a cap and trade program similar to the system now in effect for acid deposition control and to that proposed by the Clean Skies Initiative. When fully implemented, the rule is expected to reduce regional sulfur dioxide emissions by over 70% and nitrogen oxides emissions by over 60% from 2003 levels. The stringency of the cap may require some coal-fueled power plants to install additional pollution control equipment, such as wet scrubbers, which could decrease the demand for low-sulfur coal at these plants and thereby potentially reduce market prices for low-sulfur coal. Emissions are permanently capped and cannot increase. The rule is also subject to judicial challenge, which makes its impact difficult to assess.

Mercury. In February 2008, the United States Court of Appeals for the District of Columbia Circuit vacated the EPA s Clean Air Mercury Rule, which we refer to as CAMR, and remanded it to the EPA for reconsideration. The EPA is reviewing the court decision and evaluating its impacts. Before the court decision, some states had either adopted CAMR or adopted state-specific rules to regulate mercury emissions from power plants that are more stringent than CAMR. CAMR, as promulgated, would have permanently capped and reduced mercury emissions from coal-fueled power plants by establishing mercury emissions limits from new and existing coal-fueled power plants and creating a market-based cap-and-trade program that was expected to reduce nationwide emissions of mercury in two phases.

Under CAMR, coal-fueled power plants would have had 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. Regardless of how the EPA responds on reconsideration or how states implement their state-specific mercury rules, rules imposing stricter limitations on mercury emissions from power plants will likely be promulgated and implemented. Any such rules may adversely affect the demand for coal.

Carbon Dioxide. In February 2003, a number of states notified the EPA that they planned to sue the agency to force it to set new source performance standards for electric utility emissions of carbon dioxide and to tighten existing standards for sulfur dioxide and particulate matter for utility emissions. In April 2007, the U.S. Supreme Court rendered its decision in *Massachusetts v. EPA*, finding that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. The EPA s final regulations in response to the decision are not expected until December 2008. In other actions, following the *Massachusetts v. EPA* decision, the U.S. Court of Appeals for the District of Columbia Circuit remanded to the EPA new source performance standards for utility and industrial boilers promulgated in 2006 for further proceedings in light of the *Massachusetts v. EPA* decision. In June 2006, the U.S. Court of Appeals for the Second Circuit heard oral argument in a public nuisance action filed by eight states (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont) and New York City to curb carbon dioxide emissions from power plants. The parties have filed post-argument briefs on the impact of the *Massachusetts v. EPA* decision, and a decision is currently pending. If as a result of these actions the EPA were to set emission limits for carbon dioxide from electric utilities, the amount of coal our customers purchase from us could decrease.

Regional Haze. The EPA has 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 may result in additional emissions restrictions from new coal-fueled power plants whose operation may impair visibility at and around federally protected areas. This program may also require certain existing coal-fueled power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could affect the future market for coal.

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, which we refer to as SMCRA, establishes mining, environmental protection, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. Mining operators must obtain SMCRA permits and permit renewals from the Office of Surface Mining, which we refer to as OSM, or from the applicable state agency if the state agency has obtained primacy. A state agency may achieve primacy if the state regulatory agency develops a mining regulatory program that is no less stringent than the federal mining regulatory program under SMCRA.

SMCRA permit provisions include a complex set of requirements which include, among other things, coal prospecting; mine plan development; topsoil or growth medium removal and replacement; selective handling of overburden materials; mine pit backfilling and grading; disposal of excess spoil; protection of the hydrologic balance; subsidence control for underground mines; surface runoff and drainage control; establishment of suitable post mining land uses; and revegetation.

The mining permit application preparation process is initiated by collecting baseline data to adequately characterize the pre-mining environmental conditions of the permit area. This work is typically conducted by third-party consultants with specialized expertise and includes surveys and/or assessments of the following: cultural and historical resources; geology; soils; vegetation; aquatic organisms; wildlife; potential for threatened, endangered or other special status species; surface and ground water hydrology; climatology; riverine and riparian habitat; and wetlands. The geologic data is used to define and characterize the rock structures that will be encountered during the mining process. The geologic data and information derived from the other surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application.

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The mining and reclamation plans address the provisions and performance standards of the state s equivalent SMCRA regulatory program, and are also used to support applications for other authorizations and/or permits required to conduct coal mining activities. Also included in the permit application is information used for documenting surface and mineral ownership, variance requests, access roads, bonding information, mining methods, mining phases, other agreements that may relate to coal, other minerals, oil and gas rights, water rights, permitted areas, and ownership and control information required to determine compliance with Office of Surface Mining s Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

Once a permit application is prepared and submitted to the regulatory agency, it goes through an administrative completeness review and a thorough technical review. Also, before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of all reclamation obligations. After the application is submitted, a public notice or advertisement of the proposed permit is required to be given, which begins a notice period that is followed by a public comment period before a permit can be issued. It is not uncommon for a SMCRA mine permit application to take over a year to prepare, depending on the size and complexity of the mine, and anywhere from six months to two years or even longer for the permit to be issued. The variability in time frame required to prepare the application and issue the permit can be attributed primarily to the various regulatory authorities discretion in the handling of comments and objections relating to the project received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of litigation related to the specific permit or another related company s permit.

In addition to the bond requirement for an active or proposed permit, the Abandoned Mine Land Fund, which was created by SMCRA, requires a fee on all coal produced. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA s adoption in 1977. The current fee is $0.315 per ton of coal produced from surface mines and $0.135 per ton of coal produced from underground mines. In 2007, we recorded $38.0 million of expense related to these reclamation fees.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. When we apply for these permits and approvals, we may be required to prepare and present data to federal, state or local authorities data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. The authorization, permitting and implementation 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 or modification can be delayed, 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 or even years 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.

Surety Bonds. Mine operators are often required by federal and/or state laws to assure, usually through the use of surety bonds, payment of certain long-term obligations including mine closure or reclamation costs, federal and state workers compensation costs, coal leases and other miscellaneous obligations. Although surety bonds are usually noncancelable during their term, many of these bonds are renewable on an annual basis. The costs of these bonds have fluctuated in recent years while the market terms of surety bonds have generally become more unfavorable to mine operators. These changes in the terms of the bonds have been accompanied at

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times by a decrease in the number of companies willing to issue surety bonds. In order to address some of these uncertainties, we use self-bonding to secure performance of certain obligations in Wyoming. As of December 31, 2007, we have self-bonded an aggregate of $306.4 million and have posted an aggregate of $263.0 million in surety bonds and $0.5 million in cash bonds for reclamation purposes. In addition, we had approximately $134.0 million of surety bonds and letters of credit outstanding at December 31, 2007 to secure workers compensation, coal lease and other obligations.

Clean Water Act. The Clean Water Act of 1972 and comparable state laws that regulate waters of the United States can affect our mining operations directly and indirectly. One of the direct impacts on coal mining and processing operations is the Clean Water Act permitting requirements relating to the discharge of pollutants into waters of the United States. Indirect impacts of the Clean Water Act include discharge limits placed on coal-fueled power plant ash handling facilities discharges. Continued litigation of Clean Water Act issues could eventually reduce the demand for coal.

Clean Water Act requirements that may directly or indirectly affect our operations include the following:

> *Wastewater Discharge.* Section 402 of the Clean Water Act creates a process for establishing effluent limitations for discharges to streams that are protective of water quality standards through the National Pollutant Discharge Elimination System, which we refer to as the NPDES, or an equally stringent program delegated to a state regulatory agency. Regular monitoring, reporting and compliance with performance standards are preconditions for the issuance and renewal of NPDES permits that govern the discharge into waters of the United States. The imposition of future restrictions on the discharge of certain pollutants into waters of the United States could affect the permitting process, increase the costs and difficulty of obtaining and complying with NPDES permits and could adversely affect our coal production.

Under the Clean Water Act, states must conduct an anti-degradation review before approving permits for the discharge of pollutants to waters that have been designated as high quality. A state s anti-degradation regulations would prohibit the diminution of water quality in these streams. In general, waters discharged from coal mines to high quality streams may be required to meet new high quality standards. This could cause increases in the costs, time and difficulty associated with obtaining and complying with NPDES permits, and could adversely affect our coal production.

> *Dredge and Fill Permits Act.* Many mining activities, such as the development of refuse impoundments, fresh water impoundments, refuse fills, valley fills, and other similar structures, may result in impacts to waters of the United States, including wetlands, streams and, in certain instances, man-made conveyances that have a hydrologic connection to such streams or wetlands. Prior to conducting such mining activities, coal companies are required to obtain a Section 404 permit, referred to as a dredge or fill permit, from the Army Corps of Engineers, which we refer to as the Corps. The Corps is authorized to issue two types of Section 404 permits: a general permit, referred to as a nationwide permit, for surface mining activities and an individual permit. The Corps may issue nationwide permits for any category of activities involving the discharge of dredge or fill material if the Corps determines that such activities are similar in nature and will cause only minimal adverse environmental effects individually or cumulatively. Generally, the Corps has used nationwide permits to authorize impacts to waters of the United States from mining activities because the process is a more streamlined permitting approach and consumes less Corps resources.

The use of the nationwide permit to authorize stream impacts from mining activities was successfully challenged in October 2003 in federal court in southern West Virginia, but was later overturned at the court of appeals. During the appeal period only, the Corps was enjoined (only in the southern district of West Virginia) from using the nationwide permit to authorize dredge and fill activities for mining impacts. As a precaution to mitigate the uncertainty surrounding the use of the nationwide permit in these areas, we converted certain ongoing permits, pending applications, and planned applications from nationwide permits to individual permits. This precautionary step was taken to minimize the potential for future production interruptions.

You should see Item 3 Legal Proceedings beginning on page 33 for more information about certain litigation pertaining to our permits.

Mine Health and Safety Laws. Stringent safety and health standards have been imposed by federal legislation since Congress adopted the Mine Safety and Health Act of 1969. The Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed comprehensive safety and health standards on all aspects of mining operations. In addition to federal regulatory programs, all of the states in which we operate also have programs for mine safety and health regulation and enforcement. In reaction to several mine accidents in recent years, federal and state legislatures and regulatory authorities have increased scrutiny of mine safety matters and passed more stringent laws governing mining. For example, in 2006, Congress enacted the Mine Improvement and New Emergency Response Act of 2006, which we refer to as the MINER Act. The MINER Act imposes additional obligations on coal operators including, among other things, the following:

- development of new emergency response plans that address post-accident communications, tracking of miners, breathable air, lifelines, training and communication with local emergency response personnel;
- establishment of additional requirements for mine rescue teams;
- notification of federal authorities in the event of certain events;
- increased penalties for violations of the applicable federal laws and regulations; and
- requirement that standards be implemented regarding the manner in which closed areas of underground mines are sealed.

Various states, including West Virginia, have also enacted new laws to address many of the same subjects. The full financial impact of the new regulations is not yet known. However, the cost of implementation of the new safety and health regulations at the federal and state level may be substantial. In addition to the cost of implementation, there are increased penalties for violations which may also be substantial. Expanded enforcement could result in a proliferation of litigation regarding citations and orders issued as a result of the regulations.

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. The trust fund is funded by an excise tax on production of up to $1.10 per ton for coal mined in underground operations and up to $0.55 per ton for coal mined in surface operations. These amounts may not exceed 4.4% of the gross sales price. This excise tax does not apply to coal shipped outside the United States. In 2007, we recorded $65.0 million of expense related to this excise tax.

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 trigger 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.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, may affect coal mining operations by establishing requirements for the proper management, handling, transportation and disposal of hazardous wastes. Currently, certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management. Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion products generated at electric utility and independent power producing facilities, such as coal ash. In May 2000, the EPA concluded that coal combustion products do not warrant regulation as hazardous waste under RCRA. The EPA is retaining the hazardous waste exemption for these wastes. However, the EPA has determined that national non-hazardous waste regulations under RCRA Subtitle D are needed for coal combustion products disposed in surface impoundments and landfills and used as mine-fill. The Office of Surface Mining and EPA have recently proposed regulations regarding the management of coal combustion products. The EPA also concluded beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. As long as this exemption remains in effect, it is not anticipated that regulation of coal combustion waste will have any material effect on the amount of coal used by electricity generators. Most state hazardous waste laws also exempt coal combustion products, and instead treat it as either a solid waste or a special waste. Any costs associated with handling or disposal of hazardous wastes would increase our customers operating costs and potentially reduce their ability to purchase coal. In addition, contamination caused by the past disposal of ash can lead to material liability.

Climate Change. One by-product of burning coal is carbon dioxide, which is considered a greenhouse gas and is a major source of concern with respect to global warming. In November 2004, Russia ratified the Kyoto Protocol to the 1992 Framework Convention on Global Climate Change, which establishes a binding set of emission targets for greenhouse gases. With Russia s accedence, the Kyoto Protocol became binding on all those countries that had ratified it in February 2005. To date, the United States has refused to ratify the Kyoto Protocol. Although the targets vary from country to country, if the United States were to ratify the Kyoto Protocol our nation would be required to reduce greenhouse gas emissions to 93% of 1990 levels from 2008 to 2012. Canada, which accounted for approximately 3.4% of our sales volume in 2007, ratified the Kyoto Protocol in 2002. Under the Kyoto Protocol, Canada will be required to cut greenhouse gas emissions to 6% below 1990 levels in 2008 to 2012, either in direct reductions in emissions or by obtaining credits through market mechanisms. This requirement could result in reduced demand for our coal by Canadian power plants.

Future regulation of greenhouse gases in the United States could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes under the Clean Air Act, federal or state adoption of a greenhouse gas regulatory scheme, or otherwise. In 2002, the Conference of New England Governors and Eastern Canadian Premiers adopted a Climate Change Action Plan, calling for reduction in regional greenhouse emissions to 1990 levels by 2010, and a further reduction of at least 10% below 1990 levels by 2020. 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 signed onto RGGI in July 2006. The RGGI final model rule was issued in August 2006, and the participating states are developing their state rules.

Climate change developments are also taking place in western states. In September 2006, California adopted greenhouse gas legislation that prohibits long-term baseload generators from having a greenhouse gas emissions rate greater than that of combined cycle natural gas generator and that allows for long-term deals with generators that sequester carbon emissions. In January 2007, the California Public Utility Commission adopted interim greenhouse gas standards requiring all new long-term power contracts to serve baseload capacity in California to have emissions no higher than a combined-cycle gas turbine plant. In February 2007, the governors of Arizona, California, New Mexico, Oregon and Washington launched the Western Climate Initiative in an effort to develop a regional strategy for addressing climate change. The goal of the Western Climate Initiative is to identify, evaluate and implement collective and cooperative methods of reducing greenhouse gases in the region. In the spring of 2007, the governor of Utah and the premiers of British Columbia and Manitoba joined the initiative, and other states and provinces participate as observers.

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In January 2007, eight midwestern states (Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio and Wisconsin) agreed to support a voluntary registry for greenhouse gases. In November 2007, the governors of Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota and Wisconsin and the premier of Manitoba signed the Midwestern Greenhouse Gas Reduction Accord to develop and implement steps to reduce greenhouse gas emissions. These and other state climate change rules will likely require additional controls on coal-fueled power plants and industrial boilers and may even cause some users of coal to switch from coal to a lower carbon fuel. There can be no assurance at this time that a carbon dioxide cap and trade program, a carbon tax or other regulatory regime, if implemented by the states in which our customers operate, will not affect the future market for coal in those regions. Increased efforts to control greenhouse gas emissions could result in reduced demand for coal.

Endangered Species. The Endangered Species Act and other related federal and state statutes protect species threatened or endangered with possible extinction. Protection of threatened, endangered and other special status 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 or other related laws or regulations. 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. We have been able to continue our operations within the existing spatial, temporal and other restrictions associated with special status species. Should more stringent protective measures be applied to threatened, endangered or other special status species or to their critical habitat, then we could experience increased operating costs or difficulty in obtaining future mining permits. The federal government is currently considering whether to add polar bears to the list of endangered species. If the polar bear is listed as an endangered species, then that action could result in regulation of carbon dioxide emissions to address global warming. Limits on emissions of carbon dioxide could result in coal becoming a less attractive fuel source and could reduce the amount of coal our customers purchase from us.

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 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 25, 2008, we employed a total of approximately 4,030 persons, approximately 220 of whom are represented by the Scotia Employees Association. We believe that our relations with all employees are good.

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Executive Officers

The following is a list of our executive officers, their ages as of February 25, 2008 and their positions and offices during the last five years:

Name	Age	Position
C. Henry Besten, Jr.	59	Mr. Besten has served as our Senior Vice President-Strategic Development since 2002.
John W. Eaves	50	Mr. Eaves has served as our President and Chief Operating Officer since April 2006. Mr. Eaves has also been a director since February 2006. From 2002 to April 2006, Mr. Eaves served as our Executive Vice President and Chief Operating Officer. Mr. Eaves also serves on the board of directors of ADA-ES, Inc.
Sheila B. Feldman	53	Ms. Feldman has served as our Vice President-Human Resources 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 U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.
Robert G. Jones	51	Mr. Jones has served as our Vice President-Law, General Counsel and Secretary since 2000.
Paul A. Lang	47	Mr. Lang has served as our Senior Vice President-Operations 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	55	Mr. Leer has served as our Chairman and Chief Executive Officer since April 2006. 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	62	Mr. Messey has served as our Senior Vice President and Chief Financial Officer since 2000. Mr. Messey also serves on the board of directors of Baldor Electric Company and Stereotaxis, Inc.
David B. Peugh	53	Mr. Peugh has served as our Vice President-Business Development since 1995
Deck S. Slone	44	Mr. Slone has served as our Vice President-Investor Relations and Public Affairs since 2001.
David N. Warnecke	52	Mr. Warnecke has served as our Vice President-Marketing and Trading since August 2005. From June 2005 until March 2007, Mr. Warnecke served as President of our Arch Coal Sales Company, Inc. subsidiary, and from April 2004 until June 2005, Mr. Warnecke served as Executive Vice

President of Arch Coal Sales Company, Inc. Prior to June 2004, Mr. Warnecke was Senior Vice President-Sales, Trading and Transportation of Arch Coal Sales Company, Inc.

We submitted our most recent chief executive officer certification to the New York Stock Exchange on May 23, 2007.

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.

Risks Related to Our Business

A substantial or extended decline in coal prices could negatively affect our profitability and the value of our coal reserves.

Our profitability and the value of our coal reserves depend upon the prices we receive for our coal. In turn, the prices we receive for our coal depend upon factors beyond our control, including the following:

- the supply of and demand for domestic and foreign coal;
- the demand for electricity and steel;
- domestic and foreign governmental regulations and taxes, including those establishing air emission standards for coal-fueled power plants;
- regulatory, administrative and judicial decisions, including those affecting future mining permits;
- the proximity, capacity and cost of transportation facilities;
- the availability and price of alternative fuels, such as natural gas, and alternative energy sources, such as hydroelectric, wind and solar power;
- technological developments, including those intended to convert coal to liquid or gas and those aimed at capturing and sequestering carbon; and
- the effects of worldwide energy conservation measures.

Declines in the prices we receive for our coal could adversely affect our profitability and the value of our coal reserves.

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

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

- delays and difficulties in acquiring, maintaining or renewing necessary permits or mining or surface rights;

- changes or 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;
- adverse weather and natural disasters, such as heavy rains or snow and flooding;
- shortage of qualified labor;
- 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 occurs, particularly at our Black Thunder mining complex, 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 costs of mining and other industrial supplies, including steel-based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production.

Our coal mining operations use significant amounts of steel, diesel fuel, rubber tires and other mining and industrial supplies. 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 mining complex. 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 mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected. In addition, if we are unable to procure these supplies, our coal mining operations may be disrupted or we could experience a delay or halt in our 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.

Disruptions in the quantities of coal produced by our contract mine operators or purchased from other third parties could temporarily 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 and Cumberland River mining complexes. In addition, we purchase coal from third parties that we sell to our customers. Operational difficulties at contractor-operated mines or mines operated by third parties from whom we purchase coal, 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 or purchased by us. Disruptions in the quantities of coal produced for or purchased by us 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. 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 require us to pay 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, ship, 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 portion of our coal under long-term coal supply agreements, which we define as contracts with terms 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 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 A substantial or extended decline in coal prices could negatively affect our profitability and the value of our coal reserves, 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 13.

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

For the year ended December 31, 2007, we derived approximately 25.3% of our total coal revenues from sales to our three largest customers, Tennessee Valley Authority, Ameren Corporation and Intermountain Power Agency, and approximately 49.5% of our total coal revenues from sales to our ten largest customers. At December 31, 2007, we had coal supply agreements with those ten customers that expire at various times from 2008 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.

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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, 2007, we had consolidated indebtedness of approximately $1.3 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. 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 significantly affect:

- our ability to satisfy debt covenants and debt service, lease payment and other obligations;
- our ability to generate cash flow from operations or to obtain additional financing;
- our credit ratings;
- our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete; and
- our competitiveness when compared to competitors with less 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. For more information about some of the restrictions contained in our credit facilities, leases and other financial arrangements, you should see Liquidity and Capital Resources beginning on page 46.

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.

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. In addition, we have agreed to purchase coal from Magnum in order to satisfy our obligations under certain other contracts that have not yet been transferred to Magnum, the longest of which extends to the year 2017. 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. At December 31, 2007, if we had purchased the 20.4 million tons of coal required under these contracts over their duration at market prices then in effect, we would have incurred a loss of approximately $363.1 million.

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

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

Governmental regulations, including those related to the matters listed below, have significant effects on the coal mining industry:

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

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.

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 our business or our customers, may also require us or our customers to change operations significantly or incur increased costs. These regulations, if enacted in the future, could have a material adverse effect on our business, financial condition and results of operations.

You should see Safety and Environmental Regulations beginning on page 14 for more information about the various governmental regulations affecting us.

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.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization. As a result, coal users may switch to other fuels, which could affect the volume of our sales and the price of our products.

Coal contains impurities, including but not limited to sulfur, mercury, chlorine, carbon and other elements or compounds, many of which are released into the air when coal is burned. Stricter environmental regulations of emissions from coal-fueled power plants could increase the costs of using coal thereby reducing demand for coal as a fuel source and the volume and price of our coal sales. Stricter regulations could make coal a less attractive fuel alternative in the planning and building of power plants in the future.

Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, particulate matter or greenhouse gases may require the installation of costly emission control technology or the implementation of other measures, including trading of emission allowances and switching to other fuels. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from power plants, coal users may need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low-sulfur coal or switch to other fuels. Reductions in mercury emissions required by certain states will likely require some power plants to install new equipment, at substantial cost, or discourage the use of certain coals containing higher levels of mercury. Recent and new proposals calling for reductions in emissions of carbon dioxide and other greenhouse gases could significantly increase the cost of operating existing coal-fueled power

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plants and could inhibit construction of new coal-fueled power plants. Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our operations and financial results could be adversely impacted.

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 Item 3 Legal Proceedings beginning on page 33 for more information about the litigation described above.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

At December 31, 2007, we owned or controlled primarily through long-term leases approximately 99,700 acres of coal land in West Virginia, 100,300 acres of coal land in Wyoming, 98,700 acres of coal land in Illinois, 61,100 acres of coal land in Utah, 47,300 acres of coal land in Kentucky, 21,800 acres of coal land in New Mexico and 18,500 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 114,200 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 are subject to readjustment and/or extension and to earlier termination for failure to meet diligent development requirements. Certain of our 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 92,900 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 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, 2007. Recoverable reserves include only saleable coal and do not include coal which would remain unextracted, such as for support pillars, and processing losses, such as washery losses. Reserve estimates are prepared by our engineers and geologists and reviewed and updated periodically. Total recoverable reserve estimates and reserves dedicated to mines and complexes change from time to time to reflect mining activities, analysis of new engineering and geological data, changes in reserve holdings and other factors.

The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2007:

Total Assigned Reserves

(Tons in millions)

Total Assigned	Sulfur Content	Mining Method

	Recoverable Reserves	Proven	Probable	(lbs. per million Btus) <1.2	1.2-2.5	>2.5	As Received Btus per lb.(1)	Reserve Control Leased	Owned	Surface	Under-ground	Past Reserve Estimates 2005	200
oming	1,549	1,508	41	1,504	45		8,856	1,534	15	1,549		1,748	1,6
n	103	60	43	91	12		11,399	102	1		103	108	1
orado	79	60	19	79			11,695	78	1		79	74	
tral App	169	160	9	59	109	1	12,816	162	7	74	95	243	2
ois												13	
al	1,900	1,788	112	1,733	166	1	9,465	1,876	24	1,623	277	2,186	2,0

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

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Total Unassigned Reserves

(Tons in millions)

	Total Unassigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus) <1.2	1.2-2.5	>2.5	As Received Btus per lb.(1)	Reserve Control Leased	Owned	Mining Method Surface	Underground
Wyoming	398	301	97	351	47		9,653	307	91	224	174
Utah	35	16	19	31	4		10,842	34	1		35
Colorado	49	39	10	47	2		11,597	48	1		49
Central App	169	121	48	46	100	23	12,779	137	32	41	128
Illinois	376	270	106			376	11,605	58	318	2	374
Total	1,027	747	280	475	153	399	11,016	584	443	267	760

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

At December 31, 2007, approximately 16% 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. 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 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 75.4% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btus upon combustion, while an additional 6.6% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Most of our reserves are suitable for the domestic steam coal markets. A substantial portion of the low-sulfur and compliance coal reserves at the Cumberland River, Lone Mountain and Mountain Laurel mining complexes may also be used as metallurgical coal.

The carrying cost of our coal reserves at December 31, 2007 was $1.2 billion, consisting of $127.2 million of prepaid royalties and a net book value of coal lands and mineral rights of $1.1 billion.

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 24,900 acres of property to other coal operators in 2007. We received royalty income of $5.6 million in 2007 from the mining of approximately 2.1 million tons, $5.0 million in 2006 from the mining of approximately 2.4 million tons and $7.1 million in 2005 from the mining of approximately 3.0 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.

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

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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 2008.

ITEM 3. LEGAL PROCEEDINGS.

We are involved in various claims and legal actions arising in the ordinary course of business, including employee injury claims. 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.

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 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. Plaintiffs were later allowed to amend their complaint to add challenges to permits issued to our Coal-Mac, Inc. and Mingo Logan Coal Company subsidiaries, but those claims have not advanced. Rather, the court proceeded first on the earlier challenge to four permits of companies unrelated to us.

The court proceeded to rule on the challenges to those four permits in orders of March 23 and June 13, 2007. In the first of those orders, the court rescinded the four permits, finding that the Corps had inadequately assessed the likely impact of valley fills on headwater streams and had relied on inadequate or unproven mitigation to offset those impacts. That ruling could require the Corps to prepare environmental impact statements on those permits, which would slow the permit process. The ruling could, as a practical matter, affect our Coal-Mac and other future permits, but the Corps has already done an environmental impact statement on the Mingo Logan permit. In the second order, the court entered a declaratory judgment that discharges of sediment from the valley fills into sediment control ponds constructed in-stream to control that sediment must themselves be permitted and meet the limits imposed on discharges from these ponds. Unless reversed, that ruling will likely complicate the ability to construct sediment ponds in steep-sloped areas where in-stream locations are frequently the only practicable ones. Both of the district court rulings are on appeal to the Fourth Circuit Court of Appeals, and a decision is expected from that court in 2008.

While the court was considering the challenge to the four permits unrelated to our operating subsidiaries, the plaintiffs were permitted to add challenges to our Coal-Mac, Inc. and Mingo Logan Coal Company subsidiaries. Plaintiffs sought preliminary inunctions as to both operations, but later reached agreements with our operating subsidiaries that have allowed mining to progress in limited areas while the district court s rulings are on appeal.

West Virginia Flooding Litigation

Over 3,000 plantiffs have sued us and more than 180 other defendants in Wyoming, McDowell, Fayette, Kanawha, Raleigh, Boone and Mercer Counties, West Virginia 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, following the Mullins/Oceana phase I trial, in which we were not involved, the jury returned a verdict against the two non-settling defendants. However, the court set aside that verdict and granted judgment in favor of the defendants. The plaintiffs in that trial group have appealed that decision, and we, along with other defendants, have filed an amicus brief in that appeal. We were previously named in cases involving the Coal River watershed; however, on January 18, 2007, the court dismissed the plaintiffs claims involving that watershed for failure to state a claim. This ruling has also been appealed. We are also named in the remaining Upper Guyandotte watershed trial group. A trial date has not yet been set for that group.

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 2007.

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 25, 2008, our common stock closed at $54.90 on the New York Stock Exchange. On that date, there were approximately 8,200 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 $38.7 million, or $0.27 per share, in 2007 and $31.4 million, or $0.22 per share, in 2006. 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. You should see Liquidity and Capital Resources beginning on page 46 for more information about restrictions on our ability to declare dividends.

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.

	2007			
	March 31	June 30	September 30	December 31
Dividends per common share	$ 0.06	$ 0.07	$ 0.07	$ 0.07
High	33.79	42.59	37.00	45.22
Low	27.18	30.33	27.76	32.99

Close	30.69	34.80	33.74	44.93

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	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

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 two indices: a peer group, consisting of CONSOL Energy, Inc., Foundation Coal Holdings, Inc., Massey Energy Company and Peabody Energy Corp., 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, 2002;

all dividends were reinvested;

annual reweighting of the peer groups; and

you continued to hold your investment through December 31, 2007.

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 common stock.

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

	Year Ended December 31					
	2002	2003	2004	2005	2006	2007
Arch Coal, Inc.	$ 100	$ 146	$ 168	$ 377	$ 287	$ 432
S&P 400 (Midcap)	100	136	158	178	196	212
Industry Peer Group	100	163	286	482	447	806

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Issuer Purchases of Equity Securities

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. As of December 31, 2007, we have purchased 1,562,400 shares of our common stock under this program. We did not purchase any shares of our common stock under this program during the quarter ended December 31, 2007. Based on the closing price of our common stock as reported on the New York Stock Exchange on February 25, 2008, there is approximately $682.8 million of our common stock that may yet be purchased under this program.

ITEM 6. SELECTED FINANCIAL DATA.

	Year Ended December 31				
	2007 (1)	2006 (2) (3)	2005 (2) (3) (4) (5)	2004 (4) (6) (7)	2003 (4) (7) (8)
	(Amounts in thousands, except per share data)				
Statement of Operations Data:					
Coal sales revenue	$ 2,413,644	$ 2,500,431	$ 2,508,773	$ 1,907,168	$ 1,435,488
Income from operations	229,617	336,667	77,857	178,046	40,371
Income before cumulative effect of accounting change	174,929	260,931	38,123	113,706	20,340
Cumulative effect of accounting change					(3,654)
Net income	174,929	260,931	38,123	113,706	16,686
Preferred stock dividends	(219)	(378)	(15,579)	(7,187)	(6,589)
Net income available to common stockholders	$ 174,710	$ 260,553	$ 22,544	$ 106,519	$ 10,097
Basic earnings per common share before cumulative effect of accounting change	$ 1.23	$ 1.83	$ 0.18	$ 0.95	$ 0.13
Diluted earnings per common share before cumulative effect of accounting change	1.21	1.80	0.17	0.89	0.13
Basic earnings per common share	1.23	1.83	0.18	0.95	0.10
Diluted earnings per common share	1.21	1.80	0.17	0.89	0.10
Balance Sheet Data:					
Total assets	$ 3,594,599	$ 3,320,814	$ 3,051,440	$ 3,256,535	$ 2,387,649
Working capital	(35,370)	46,471	216,376	355,803	237,007
Long-term debt, less current maturities	1,085,579	1,122,595	971,755	1,001,323	700,022
Other long-term obligations	420,819	391,819	382,256	800,332	722,954
Stockholders equity	1,531,686	1,365,594	1,184,241	1,079,826	688,035
Common Stock Data:					

Dividends per share	$ 0.2700	$ 0.2200	$ 0.1600	$ 0.1488	$ 0.1152
Shares outstanding at year-end	143,158	142,179	142,741	125,716	106,410
Cash Flow Data:					
Cash provided by operating activities	$ 330,810	$ 308,102	$ 254,607	$ 148,728	$ 162,361
Depreciation, depletion and amortization	242,062	208,354	212,301	166,322	158,464
Capital expenditures	488,363	623,187	357,142	292,605	132,427
Dividend payments	38,945	31,815	27,639	24,043	17,481
Operating Data:					
Tons sold	135,010	134,976	140,202	123,060	100,634
Tons produced	126,624	126,015	129,685	115,861	93,966
Tons purchased from third parties	8,495	10,092	11,226	12,572	6,602

(1) On June 29, 2007, we sold select assets and related liabilities associated with our Mingo Logan-Ben Creek mining complex in West Virginia for $43.5 million. We recognized a net gain of $8.9 million in 2007 resulting from the sale.

(2) 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 of 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.

(3) On December 31, 2005, we sold all of the stock of three subsidiaries and their associated mining operations and coal reserves in Central Appalachia to Magnum. 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.

(4) 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 reflect the split.

(5) 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.

(6) 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.

(7) 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.

(8) 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

We are one of the largest coal producers in the United States. For the year ended December 31, 2007, we sold approximately 135.0 million tons of coal, including approximately 8.6 million tons of coal we purchased from third parties, fueling approximately 6% of all electricity generated in the United States. Since federal and state environmental regulations limit the amount of sulfur dioxide that power plants may emit, we believe demand for low sulfur coal exceeds demand for other types of coal. As a result, we focus on mining, processing and marketing bituminous and sub-bituminous coal with low sulfur content for sale to domestic power plants, steel mills and industrial facilities.

In 2007, we estimate that U.S. coal consumption rose by approximately 2% to 1.2 billion tons, according to estimates provided by the EIA. Conversely, according to the EIA, domestic coal production declined by approximately 1.5% in 2007. In 2008, we expect continued growth in electricity demand, although at lower levels than in 2007 given the forecast for slower U.S. economic growth. In addition, we expect strengthening global demand for coal to increase U.S. coal exports, particularly as traditional coal export countries, such as Australia, China and South Africa, experience mine, port, rail and labor challenges. We estimate that higher domestic coal demand and higher coal exports, together with decreased production particularly in the Central Appalachia region of the United States, will adversely affect the availability of domestic coal in the coming years and result in upward pressure on domestic coal prices. As such, 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, 2007, our expected unpriced production approximated 15 million to 25 million tons in 2008, 85 million to 95 million tons in 2009 and 95 million to 105 million tons in 2010.

The locations of our mines enable us to ship coal to most of the major coal-fired power plants in the United States. 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.

The Powder River Basin is located in northeastern Wyoming and southeastern Montana. The coal we mine from surface operations in this region has a very low sulfur content and a low heat value compared to the other regions in which we operate. 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. Because Powder River Basin coal is generally lower in heat value, some power plants must blend it with higher Btu coal or retrofit existing coal plants to accommodate Powder River Basin coal. The Western Bituminous region includes western Colorado, eastern Utah and southwestern Wyoming. Coal we mine from underground mines in this region typically has a low sulfur content and varies in heat value. Central Appalachia includes eastern Kentucky, Virginia and southern West Virginia. Coal we mine from both surface and underground mines in this region generally has a high heat value and low sulfur content. In addition, a portion of the coal we produce in the Central Appalachia region consists of metallurgical coal. We are typically able to sell metallurgical coal to customers in the steel industry at prices that exceed the price we are able to sell steam coal to power plants and industrial facilities because metallurgical coal has high heat content, low expansion pressure, low sulfur content and various other chemical attributes.

In 2007, we continued the efforts we had begun in prior periods aimed at positioning our operations for increasing global and domestic coal demand. During the first half of 2007, we installed a replacement longwall at our Sufco mining complex in Utah. In addition, we began construction of a new loadout facility at our Black Thunder mining complex in Wyoming. This facility, which we have strategically located in relation to the direction of our mining activities, will replace the facility that we currently lease from a third party under an agreement set to expire within the next year. In 2007, we also continued development of a new reserve area at our West Elk mining complex in Colorado and commenced production at our Mountain Laurel mining complex in Central Appalachia. Coal produced at our lower-cost Mountain Laurel mining complex will replace the coal we have historically produced at the higher-cost Mingo Logan-Ben Creek mining complex that we sold to a subsidiary of Alpha Natural Resources at the end of the first half of 2007. We also expect that the opening of the Mountain Laurel complex will enable us to take advantage of increasing global metallurgical coal demand.

Items Affecting Comparability of Reported Results

The comparability of our operating results for the years ended December 31, 2007, 2006 and 2005 is affected by the following significant items:

Sale of Mingo Logan-Ben Creek mining complex On June 29, 2007, we sold selected assets and related liabilities associated with our Mingo Logan-Ben Creek mining complex in West Virginia to a subsidiary of Alpha Natural Resources, Inc. for $43.5 million. During the year ended December 31, 2007, our Ben Creek operations contributed coal sales of 1.2 million tons, revenues of $75.1 million and income from operations of $9.1 million. During the year ended December 31, 2006, our Ben Creek operations contributed coal sales of 4.0 million tons, revenues of $243.8 million and income from operations of $19.5 million. During the year ended December 31, 2005, our Ben Creek operations contributed coal sales of 4.7 million tons, revenues of $261.5 million, and income from operations of $15.2 million. We recognized a net gain of $8.9 million in the year ended December 31, 2007 resulting from this transaction, net of accrued losses of $12.5 million on firm commitments to purchase coal through 2008 to supply below-market sales contracts that can no longer be sourced from our operations and $4.9 million of employee-related payments. We recorded the gain as a component of other operating income, net.

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. The three subsidiaries were Hobet Mining, Inc., Apogee Coal Company and Catenary Coal Company, which included the Hobet 21, Arch of West Virginia, Samples and Campbells Creek mining complexes. For the year ended December 31, 2005, these complexes sold 12.7 million tons of coal, had revenues of $509.8 million and incurred a loss from operations of $8.3 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.

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 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 September 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. We are recognizing the deferred gain over the term of the lease.

West Elk combustion event A 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.

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. Prior to 2006, 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.

Results of Operations

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Summary. Our results during 2007 when compared to 2006 were affected primarily by changes in our regional sales mix; weaker market conditions; higher depreciation, depletion and amortization, higher cash costs in the Powder River Basin; the net effect of the insurance proceeds we recorded in 2006 related to the West Elk idling and the effect of the idling in the first quarter of 2006; and an increase in interest expense. In response to the soft market conditions, we reduced production volume targets in all operating segments in 2007.

Revenues. The following table summarizes information about coal sales during the year ended December 31, 2007 and compares those results to the comparable information for the year ended December 31, 2006:

	Year Ended December 31		Increase (Decrease)	
	2007	2006	Amount	%

	(Amounts in thousands, except per ton data)			
Coal sales	$ 2,413,644	$ 2,500,431	$ (86,787)	(3.5)%
Tons sold	135,010	134,976	34	
Coal sales realization per ton sold	$ 17.88	$ 18.53	$ (0.65)	(3.5)%

Coal sales. Coal sales decreased from 2006 to 2007 primarily due to changes in our segment mix, despite flat overall sales volume. An increase in Powder River Basin sales volumes and a decrease in Central Appalachia sales volumes resulted in a lower average sales price because Powder River Basin coal has a lower average sales price per ton than Central Appalachia coal. We have provided more information about the tons sold and the coal sales realizations per ton by operating segment under the heading Operating segment results on page 41.

Expenses, costs and other. The following table summarizes expenses, costs and other operating income, net for the year ended December 31, 2007 and compares those results to the comparable information for the year ended December 31, 2006:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2007	2006	$	%
	(Dollars in thousands)			
Cost of coal sales	$ 1,888,285	$ 1,909,822	$ 21,537	1.1%
Depreciation, depletion and amortization	242,062	208,354	(33,708)	(16.2)
Selling, general and administrative expenses	84,446	75,388	(9,058)	(12.0)
Other operating income, net	(30,766)	(29,800)	966	3.2
Total	$ 2,184,027	$ 2,163,764	$ (20,263)	(0.9)%

Cost of coal sales. Cost of coal sales decreased from 2006 to 2007 primarily due to the effect of the change in our segment mix, as the Powder River Basin s production costs per ton are lower than costs for our other regions. We also purchased fewer tons to satisfy contracts we retained after the sale to Magnum. This decrease was partially offset by higher unit costs in the Powder River Basin, primarily reflecting higher commodity and supplies costs, and higher unit costs in the Western Bituminous region. Higher unit costs in the Western Bituminous region were primarily due to the impact of insurance proceeds we recognized in 2006 related to the West Elk combustion-related event, which more than offset the impact of the idling in the first quarter of 2006. We have provided more information about our operating segments under the heading Operating segment results on page 41.

Depreciation, depletion and amortization. The increase in depreciation, depletion and amortization expense from 2006 to 2007 is due primarily to the costs of ongoing capital improvement and mine development projects that we capitalized in 2006 and 2007 and a decrease in the amortization of deferred gains on acquired sales contracts. We have provided additional information concerning our capital spending in the section entitled Liquidity and Capital Resources beginning on page 46.

Selling, general and administrative expenses. The increase in selling, general and administrative expenses from 2006 to 2007 is primarily due to an increase in the expense associated with our deferred compensation plans, which results from changes in the value of our common stock, as well as other employee compensation costs.

Other operating income, net. The increase in other operating income, net in 2007 compared to 2006 is due primarily to the following:

- an $8.9 million gain on the 2007 sale of the Ben Creek complex discussed previously;

- a $6.0 million gain on the sale of non-core reserves in the Powder River Basin and a $2.4 million gain on the sale of non-core reserves in Central Appalachia, both in 2007;

- unrealized gains of $5.0 million in 2007 on coal derivatives entered into for trading purposes; and expenses of $8.7 million during 2006 related to the Magnum transaction.

These increases in other operating income are partially offset by:

a decrease of $15.2 million related to realized and unrealized gains in 2006 associated with sulfur dioxide emission allowance put options and swaps;

a gain of $10.3 million in 2006 on the acquisition of our interest in Knight Hawk Holdings, LLC, representing the difference between the fair value of coal reserves we surrendered for the interest and their carrying value; and

a decrease of $3.3 million in the amount of income from equity investments.

Operating segment results. The following table shows results by operating segment for the year ended December 31, 2007 and compares those amounts to the comparable information for the year ended December 31, 2006:

	Year Ended December 31		Increase (Decrease)	
	2007	2006	Amount	%
	(Amounts in thousands, except per ton data)			
Powder River Basin				
Tons sold	99,145	96,246	2,899	3.0%
Coal sales realization per ton sold(1)	$ 10.59	$ 10.82	$ (0.23)	(2.1)%
Operating margin per ton sold(2)	$ 1.23	$ 2.15	$ (0.92)	(42.8)%
Western Bituminous				
Tons sold	19,362	18,122	1,240	6.8%
Coal sales realization per ton sold(1)	$ 24.73	$ 22.42	$ 2.31	10.3%
Operating margin per ton sold(2)	$ 5.11	$ 6.86	$ (1.75)	(25.5)%
Central Appalachia				
Tons sold	16,503	20,608	(4,105)	(19.9)%
Coal sales realization per ton sold(1)	$ 47.87	$ 46.90	$ 0.97	2.1%
Operating margin per ton sold(2)	$ 3.89	$ 2.95	$ 0.94	31.9%

(1) 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, 2007, transportation costs per ton billed to customers were $0.03 for the Powder River Basin, $3.17 for the Western Bituminous region and $1.82 for Central Appalachia. Transportation costs per ton billed to customers for the year ended December 31, 2006 were $0.02 for the Powder River Basin, $2.91 for the Western Bituminous region and $1.54 for Central Appalachia.

(2) Operating margin per ton is calculated as the result of coal sales revenues less cost of coal sales and depreciation, depletion and amortization divided by tons sold.

Powder River Basin Sales volume in the Powder River Basin increased slightly in 2007 over 2006 levels due to increased shipments from the Coal Creek mine, which was restarted during 2006, and higher volumes of brokerage activity. These volumes were partially offset by a decrease at the Black Thunder mining complex due to planned volume reductions in response to the weaker market conditions in 2007, as well as weather-related shipment challenges and an unplanned belt outage that occurred in the first quarter of 2007. Decreases in sales prices during 2007 when compared with 2006 primarily reflect the higher volumes from the Coal Creek mining complex, which has a lower price due to its lower heat content, and lower sulfur dioxide emission allowance adjustments. On a per-ton basis, operating margins in 2007 decreased from 2006 due in part to the decrease in per-ton coal sales prices and an increase in per-ton costs. The increase in per-ton costs resulted primarily from higher diesel fuel prices and higher labor, tire and leasing costs.

Western Bituminous In the Western Bituminous region, sales volume increased during 2007 when compared with 2006, reflecting a full year of production at the West Elk and Skyline mining complexes. The West Elk mining complex was idle during the first quarter of 2006 after the combustion-related event in the fourth quarter of 2005, and the Skyline longwall commenced mining in a new reserve area in the second quarter of 2006. These increases were partially offset by the lower volumes from planned volume reductions in response to the weaker market conditions in 2007. Higher sales prices during 2007 represent higher base pricing resulting from the roll-off of lower-priced legacy contracts. Operating margins per ton for 2007 decreased from 2006 primarily due to the impact of insurance proceeds we recognized in 2006 related to the West Elk combustion-related event and higher depreciation, depletion and amortization costs resulting from the impact of the installation of a new longwall at the Sufco mining complex. These factors offset the impact of the improved per-ton coal sales prices. The $41.9 million of insurance proceeds we recognized in 2006 offset the estimated $30.0 million adverse effect of the idling in the first quarter of 2006.

Central Appalachia Our sales volumes in Central Appalachia decreased during 2007 when compared with 2006 primarily due to higher volumes of coal shipped during 2006 associated with sales contracts we retained after the sale of certain Central Appalachia operations in 2005 to Magnum and the sale of the Ben Creek operations at the end of the second quarter of 2007. The commencement of production at the Mountain Laurel complex at the beginning of the fourth quarter of 2007 partially offset these effects. The higher realized prices in 2007 reflect the decrease in the volumes sold under the lower-priced contracts we retained after the sale to Magnum. Operating margins per ton for 2007 increased from 2006 due to the lower volumes sold under the contracts retained after the Magnum sale and the commencement of production at the low-cost Mountain Laurel complex. The tons sold under the retained contracts are purchased from Magnum at an amount equal to the contracted sales price, which diluted our per-ton margins in 2006. Difficult geologic conditions in certain locations, particularly at our Mingo Logan-Ben Creek complex, and higher depreciation, depletion and amortization costs partially offset the positive impact on operating margin.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2007 and compares that information to the comparable information for the year ended December 31, 2006:

	Year Ended December 31		Decrease in Net Income	
	2007	2006	$	%
	(Amounts in thousands)			
Interest expense	$ (74,865)	$ (64,364)	$ (10,501)	(16.3)%
Interest income	2,600	3,725	(1,125)	(30.2)
Total	$ (72,265)	$ (60,639)	$ (11,626)	(19.2)%

The increase in interest expense during 2007 compared to the year-ago period resulted primarily from an increase in outstanding borrowings under our various lines of credit, which was partially offset by an increase in capitalized interest. We capitalized $18.0 million of interest during the year ended December 31, 2007 and $14.8 million during the year ended December 31, 2006. For more information on our ongoing capital improvement and development projects, you should see Liquidity and Capital Resources beginning on page 46.

Other non-operating expense. The following table summarizes our other non-operating expense for the year ended December 31, 2007 and compares that information to the comparable information for the year ended December 31, 2006:

	Year Ended December 31		Increase in Net Income	
	2007	2006	$	%
	(Amounts in thousands)			
Other non-operating expense:				
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	$ (1,919)	$ (4,836)	$ 2,917	60.3%
Other non-operating expense	(354)	(2,611)	2,257	86.4

Total	$ (2,273)	$ (7,447)	$ 5,174	69.5%

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. All deferred amounts have now been recognized. Other non-operating income includes mark-to-market adjustments related to certain swap activity that does not qualify for hedge accounting. No swaps were outstanding at December 31, 2007.

Income taxes. Our effective tax rate is sensitive to changes in estimates of annual profitability and percentage depletion deductions. The income tax benefit of $19.9 million in 2007 compared with our income tax provision of $7.7 million in 2006 results from lower pre-tax income in 2007 and the benefit of a reduction in our valuation allowance against deferred tax assets of $38.7 million compared with higher pre-tax income in 2006 offset by a valuation allowance reduction of $49.1 million.

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

Summary. Our results for 2006 reflect higher margins driven primarily by increased price realizations 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 weaker market conditions at the end of 2006. 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 mining complex in Wyoming, which restarted production in 2006, and our Skyline longwall mining complex in Utah, which commenced mining in a new reserve area in 2006.

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	Amount	%
	(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 realizations per ton by operating segment under the heading Operating segment results on page 45.

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 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 segments under the heading Operating segment results on page 45.

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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 certain Central Appalachia operations in 2005. We have provided additional information concerning our capital spending during 2006 in the section entitled Liquidity and Capital Resources beginning on page 46.

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 38 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 between years 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 between periods (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, representing the difference between the fair value of coal reserves we surrendered for the interest and their carrying value;

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 segment results. The following table shows results by operating segment for the year ended December 31, 2006 and compares those amounts to the comparable information for the year ended December 31, 2005:

	Year Ended December 31		Increase (Decrease)	
	2006	2005	Amount	%
	(Amounts in thousands, except per ton data)			
Powder River Basin				
Tons sold	96,246	91,471	4,775	5.2%
Coal sales realization per ton sold(1)	$ 10.82	$ 8.20	$ 2.62	32.0%
Operating margin per ton sold(2)	$ 2.15	$ 0.95	$ 1.20	126.3%
Western Bituminous				
Tons sold	18,122	18,199	(77)	(0.4)%
Coal sales realization per ton sold(1)	$ 22.42	$ 19.01	$ 3.41	17.9%
Operating margin per ton sold(2)	$ 6.86	$ 3.27	$ 3.59	109.8%
Central Appalachia				
Tons sold	20,608	30,532	(9,924)	(32.5)%
Coal sales realization per ton sold(1)	$ 46.90	$ 42.73	$ 4.17	9.8%
Operating margin per ton sold(2)	$ 2.95	$ (0.59)	$ 3.54	600.0%

(1) 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 $1.54 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.

(2) Operating margin per ton is calculated as the result of coal sales revenues less cost of coal sales and depreciation, depletion and amortization divided by tons sold.

Powder River Basin Sales volume increased in the Powder River Basin as a result of the restart of the Coal Creek mining complex in the second quarter of 2006 and rail service that improved during 2006 when compared to 2005. The increase in coal sales prices in 2006 in the Powder River Basin resulted from higher contract pricing when compared to 2005, due primarily to the expiration of lower-priced legacy contracts. On a per-ton basis, operating margins in 2006 increased significantly from 2005 primarily due to the increase in per-ton coal sales realizations, partially offset by increased production taxes and coal royalties that 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 In the Western Bituminous region, the effect of an extended longwall move at the Dugout Canyon mining complex offset a portion of the 1.5 million tons sold from our Skyline mining complex, which commenced production in a new reserve area in the second quarter of 2006. The increase in coal sales prices in the Western Bituminous region in 2006 resulted from higher contract pricing when compared to 2005, due primarily to the expiration of lower-priced legacy contracts. 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 the idling of the West Elk complex in the first quarter of 2006, an extended longwall move at our Dugout Canyon mining complex, higher coal royalties and production taxes, which we pay as a percentage of sales, and higher repair and supplies costs.

Central Appalachia Our sales volumes in Central Appalachia decreased as a result of the sale of operations to Magnum described previously. The increase in our coal sales prices in Central Appalachia in 2006 resulted from higher contract pricing when compared to 2005, due primarily to the expiration of lower-priced legacy contracts. The sale to Magnum of certain operations with lower-priced legacy contracts also helped to improve our average coal sales price per ton. Operating margins per ton in 2006 increased significantly from 2005 primarily as a result of the sale to Magnum, due to operating losses at these operations in 2005.

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 amount 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 46. 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.

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.

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, accounts receivable securitization or commercial paper programs. We believe that cash generated from operations, borrowing under our credit facilities and sales of assets will be sufficient to meet working capital requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years. Our ability to satisfy debt service obligations, to fund planned capital expenditures, to make acquisitions, to repurchase our common shares 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		
	2007	2006	2005
	(Amounts in thousands)		
Cash provided by (used in):			
Operating activities	$ 330,810	$ 308,102	$ 254,607
Investing activities	(424,995)	(688,005)	(291,543)
Financing activities	96,742	121,925	(25,730)

Cash provided by operating activities increased $22.7 million in 2007 compared to 2006, despite a decrease in earnings, primarily as a result of transactions in 2006 related to our sale of certain Central Appalachia operations to Magnum on December 31, 2005. We made payments of $50.2 million in 2006 related to that transaction, involving the purchase of coal and certain operating expenses pursuant to the purchase agreement. In addition, we purchased coal in 2006 to satisfy below-market contracts that we could not source from our remaining operations.

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 the effect of certain transactions with Magnum discussed above.

Cash used in investing activities in 2007 was $263.0 million less than in 2006, primarily due to a $134.8 million decrease in capital expenditures, an increase of $69.5 million in proceeds from asset sales, and a decrease of $36.4 in payments to acquire equity interests in other companies that are 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 may also acquire coal reserves opportunistically. During 2006 and 2007, we made the second and third of five annual payments of $122.2 million on the Little Thunder federal coal lease. In addition, during 2007, we acquired additional property and reserves of approximately $97.4 million. Of the remaining capital spending in 2007, major projects included the completion of development at the Mountain Laurel complex in Central Appalachia, ongoing development of a new reserve area at the West Elk mining complex in Colorado, payments for the replacement longwall now in service at our Sufco mining complex in Utah and costs to construct the Black Thunder mining complex s new loadout. The Mountain Laurel longwall commenced production on October 1, 2007. In the prior year, in addition to spending on the Mountain Laurel development, we also had spending related to the restart of the Coal Creek mining complex and the commencement of mining in a new reserve area at our Skyline mining complex.

Cash inflows from investing activities in 2007 included a recovery of $18.3 million from the lease of equipment in the Powder River Basin. We had previously made deposits to purchase the equipment, primarily in the fourth quarter of 2006. Our proceeds from asset sales in 2007 included $43.5 million related to the sale of the Ben Creek complex and $26.0 million from the sale of non-core reserves in the Powder River Basin and Central Appalachia.

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 mining complex and progress payments related to the purchase of a replacement longwall at our Sufco mining complex resulted in an increase in capital expenditures in 2006 compared to 2005. 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 anticipate that capital expenditures during 2008 will range from approximately $445 million to $505 million, including reserve additions of approximately $135 million to $165 million. Reserve additions in 2008 will include the fourth of five payments of $122.2 million for the Little Thunder coal lease. The 2008 estimate also includes capital expenditures related to development work at certain of our mining operations, including the development of a new seam, with a new longwall, at the West Elk mining complex and continuing work on the new loadout at Black Thunder. We anticipate that we will fund these capital expenditures with available cash, cash generated from operations and existing credit facilities.

Cash provided by financing activities decreased $25.2 million in 2007 compared to 2006. The decrease results primarily from a decrease in borrowings on the revolving credit facility and other lines of credit, including those under the accounts receivable securitization and commercial paper programs, offset by a decrease in shares we repurchased during 2007 when compared with 2006. We had available borrowing capacity of approximately $640.0 million under our lines of credit at December 31, 2007. 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. We increased our dividend rate in April 2006 and 2007 and as a result, dividends paid increased $7.1 million.

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. 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 also spent $43.9 million during 2006 under the share repurchase program.

At December 31, 2007, debt amounted to $1,303.2 million, or 46% of capital employed, compared to $1,173.8 million, or 46% of capital employed, at December 31, 2006. Based on the level of consolidated indebtedness and prevailing interest rates at December 31, 2007, debt service obligations for 2008, which include the maturities of principal and interest payments, are estimated to be $284.4 million.

On August 15, 2007, we entered into a commercial paper placement program to provide short-term financing at rates that are generally lower than the rates available under our revolving credit facility. Under the program, as amended, we may sell up to $75.0 million in interest-bearing or discounted short-term unsecured debt obligations with maturities of no more than 270 days. The commercial paper placement program is supported by an unsecured $75.0 million revolving credit facility with a maturity date of June 7, 2008. As of December 31, 2007, we had $75.0 million outstanding under the agreement with a weighted-average interest rate of 5.08% and maturity dates ranging from two to 81 days.

Our revolving credit facility allows for up to $800.0 million of borrowings and matures June 23, 2011. We had borrowings outstanding under the revolving credit facility of approximately $160.0 million December 31, 2007 and $103.0 million at December 31, 2006. 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, as amended. The weighted average interest rate of borrowings outstanding at December 31, 2007 was 6.30%.

Our revolving 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, 2007.

We have a receivable securitization program of $150.0 million. Under the terms of the program, eligible trade receivables consist of trade receivables generated by our operating subsidiaries. Outstanding borrowings under the program were approximately $90.8 million at December 31, 2007 and $89.2 million at December 31, 2006. 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. The average cost of borrowing under the securitization program was approximately 5.79% at December 31, 2007. 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.

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.

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				
	2007	2006	2005	2004	2003
Ratio of earnings to combined fixed charges and preference dividends(1)	2.40x	3.93x	N/A	2.57x	1.14x

(1) Earnings consist of income (loss) from continuing operations before income taxes and are adjusted to include only distributed income from affiliates accounted for on the equity method and 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. Combined fixed charges and preference dividends exceeded earnings by $13.1 million for the year ended December 31, 2005.

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Contractual Obligations

The following is a summary of our significant contractual obligations as of December 31, 2007:

	Payments Due by Period				
	2008	2009-2010	2011-2012	After 2012	Total
	(Amounts in thousands)				
Long-term debt, including related interest	$ 284,355	$ 132,750	$ 251,966	$ 982,063	$ 1,651,134
Operating leases	30,612	57,472	41,838	43,981	173,903
Coal lease rights	145,802	179,083	36,052	18,833	379,770
Coal purchase obligations	313,712	200,313	102,566	296,887	913,478
Unconditional purchase obligations	236,978	10,376			247,354
Total contractual obligations	$ 1,011,459	$ 579,994	$ 432,422	$ 1,341,764	$ 3,365,639

Interest on long-term debt was calculated using rates in effect at December 31, 2007 for the remaining term of outstanding borrowings.

Coal lease rights represent non-cancelable royalty lease agreements, as well as federal lease bonus payments due. In particular, remaining payments due under the Little Thunder lease in Wyoming will be paid in two equal annual installments of $122.2 million in 2008 and 2009.

Our coal purchase obligations include purchase obligations in the over-the-counter market, as well as unconditional purchase obligations with coal suppliers. Additionally, they include coal purchase obligations incurred with the sale of certain Central Appalachia operations in 2005 and the sale of the Mingo Logan-Ben Creek complex in 2007 to supply ongoing customer sales commitments.

Unconditional purchase obligations include open purchase orders, which have not been recognized as a liability. The commitments in the table above relate to commitments for the purchase of materials and supplies, payments for services and capital expenditures.

The table above excludes our asset retirement obligations. Our consolidated balance sheet reflects a liability of $224.5 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 52, 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 52 for more information about these assumptions. We expect to make contributions of

$2.5 million to our pension plans in 2008. 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.

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, coal lease obligations and other obligations as follows as of December 31, 2007:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other	Total
			(Amounts in thousands)		
Self bonding	$ 306,385	$	$	$	$ 306,385
Surety bonds	262,995	45,239	14,600	15,507	338,341
Letters of credit			46,352	12,261	58,613

We have agreed to continue to provide surety bonds and letters of credit for the reclamation 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 a specified period of time, then Magnum must post a letter of credit in our favor in the amount of the obligations. At December 31, 2007, we had $92.0 million of surety bonds related to properties sold to Magnum, which are included in the table.

Magnum also acquired certain coal supply contracts with customers who have not consented to the assignment of the contract to Magnum. We have committed to purchase coal from Magnum to sell to those customers at the same price we are charging the customers for the sale. In addition, certain contracts have been assigned to Magnum, but we have guaranteed Magnum s performance under the contracts. The longest of the coal supply contracts extends to the year 2017. 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 contracts from our existing operations. At market prices effective at December 31, 2007, the cost of purchasing 15.4 million tons of coal to supply the contracts that have not been assigned over their duration would exceed the sales price under the contracts by approximately $265.7 million, and the cost of purchasing 5.0 million tons of coal to supply the assigned and guaranteed contracts over their duration would exceed the sales price under the contracts by approximately $97.4 million. We have also guaranteed Magnum s performance under certain operating leases, the longest of which extends through 2011. If we were required to perform under our guarantees of the operating lease agreements, we would be required to make $10.3 million of lease payments. We do not believe that it is probable that we would have to purchase replacement coal or fulfill our obligations under the lease guarantees and therefore, no liability has been recorded for these potential losses as of December 31, 2007. 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 $61.0 million at December 31, 2007, of which none is recorded as a liability in 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 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. We have begun 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. The outcome of the negotiations is uncertain, however, any change that impacts us related to an IRS negotiation may result in a non-cash decrease in deferred income tax assets that could fall within a range of zero to $25.0 million.

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 our 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 the majority of our 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 expected cash flows used to determine the asset retirement obligation. At December 31, 2007, we had recorded asset retirement obligation liabilities of $224.5 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, 2007, we estimate that the aggregate undiscounted cost of final mine closure is approximately $538.0 million.

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.

Derivative Financial Instruments

We use derivative financial instruments to manage exposures to commodity prices and interest rates. We also enter into over-the-counter coal positions for trading purposes. All 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. The amount of ineffectiveness recognized in other operating (income) expense, net relating to our heating oil derivatives was a gain of $1.4 million for the year ended December 31, 2007. Ineffectiveness was insignificant for the year ended December 31, 2006.

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 $2.7 million in cash to the plans during the year ended December 31, 2007 and $19.3 million in cash and stock to the plans during the year ended December 31, 2006. 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.

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.

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

> The expected long-term rate of return on plan assets is an assumption reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan s investment targets are 65% equity, 30% fixed income securities and 5% cash. Investments are rebalanced on a periodic basis to stay within these targeted guidelines. The long-term rate of return assumption used to determine

pension expense was 8.5% for 2007 and 8.25% for 2006. 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 2007 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 5.9% for 2007 and 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. The impact of lowering the discount rate 0.5% for 2007 would have been an increase in expense of approximately $2.4 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 2007 (and pension expense for 2008), we changed our discount rate to 6.5%.

We also currently provide certain postretirement medical and 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 benefit 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 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.

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 5.9% for 2007 and 5.8% for 2006. Had the discount rate been lowered by 0.5% in 2007, we would have incurred additional expense of $0.6 million.

For the measurement of our year-end other postretirement obligation for 2007 and postretirement expense for 2008, we changed our discount rate to 6.5%. During 2007, the postretirement benefit plans were amended to improve benefits to participants. As a result of the amendment, annual retiree contribution increases have been limited so as not to exceed 25% of the previous year s total contribution. Prior to the amendment, all medical cost increases were passed on to the retirees and had no impact on the plan.

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.

As of January 1, 2007, we adopted 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. Upon adoption of FIN 48, we increased our liability for unrecognized tax benefits by $1.0 million, including interest and penalties of $0.2 million, which was recorded as a reduction of the beginning balance of retained earnings.

Accounting Standards Issued and Not Yet Adopted

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 do not expect the impact of adoption will be material.

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

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.

We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements, and to a limited extent, through the use of derivative instruments. At December 31, 2007, our expected unpriced production approximated 15 million to 25 million tons in 2008, 85 million to 95 million tons in 2009 and 95 million to 105 million tons in 2010.

We are exposed to commodity price risk in our trading of coal, which represents the potential loss that could be caused by an adverse change in the market value of coal. Our coal trading portfolio included forward and option contracts at December 31, 2007. We had no positions entered into for trading purposes as of December 31, 2006. With respect to our coal trading positions, a $0.50 decrease in Powder River Basin coal prices and a $2 decrease in Central Appalachia coal prices would cause a $2.9 million decrease in the fair value of these positions. The timing of the estimated future realization of the value of our trading portfolio is 30% in 2008, 68% in 2009 and 2% in 2010.

We are also exposed to the risk of fluctuations in cash flows related to our purchase of diesel fuel. We use approximately 45 million gallons of diesel fuel annually in our operations. 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, and in doing so had protected approximately 23% of our forecasted purchases for 2008 at December 31, 2007. At December 31, 2006, we had protected approximately 68% of our forecasted purchases for 2007. 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. At December 31, 2007, a $0.25 per gallon decrease in the price of heating oil would result in a $2.2 million increase in our expense in 2008 resulting from heating oil derivatives, which would be offset by a decrease in the cost of our physical diesel purchases.

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2007, $977.4 million of our outstanding debt had fixed interest rates, primarily our 6.75% Senior Notes, and $325.8 million of outstanding borrowings had interest rates that fluctuated based on changes in the respective market rates. A one percentage point increase in the interest rates related to these borrowings would

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result in an annualized increase in interest expense of $3.3 million, based on borrowing levels at December 31, 2007.

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, 2007. 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, 2007 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-4, 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 headings Code of Conduct, Director Biographies and Board Meetings and Committees appearing in the section entitled Corporate Governance Practices and the information appearing in the section entitled Section 16(a) Beneficial Ownership Reporting Compliance in our proxy statement to be distributed to stockholders in connection with the 2008 annual meeting.

ITEM 11. EXECUTIVE COMPENSATION.

We incorporate by reference the information under the headings Compensation Discussion and Analysis, Summary Compensation Table, Grants of Plan-Based Awards for the Year Ended December 31, 2007, Outstanding Equity Awards at December 31, 2007, Option Exercises and Stock Vested for the Year Ended December 31, 2007, Pension Benefits, Nonqualified Deferred Compensation, Potential Payments Upon Termination of Employment or Change-in-Control and Director Compensation for the Year Ended December 31, 2007 appearing in the section entitled Executive and Director Compensation in our proxy statement to be distributed to stockholders in connection with the 2008 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 sections entitled Security Ownership of Directors and Executive Officers and Security Ownership of Certain Beneficial Owners in our proxy statement to be distributed to stockholders in connection with the 2008 annual meeting.

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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, 2007, the weighted average exercise price of those options, and the number of shares of common stock remaining available for future issuance at December 31, 2007, excluding shares to be issued upon exercise of outstanding options. No warrants or rights had been issued under the plan as of December 31, 2007.

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	2,849,963	$ 18.19	3,943,297
Equity compensation plans not approved by security holders			
Total	2,849,963	$ 18.19	3,943,297

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 Practices in our proxy statement to be distributed to stockholders in connection with the 2008 annual meeting.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

We incorporate by reference the information in the section entitled Ratification of the Appointment of Independent Public Accounting Firm in our proxy statement to be distributed to stockholders in connection with the 2008 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.

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FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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Report of Management and Management s Report on Internal Control over Financial Reporting	F-4
Consolidated Statements of Income for the Years Ended December 31, 2007, 2006 and 2005	F-5
Consolidated Balance Sheets at December 31, 2007 and 2006	F-6
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Notes to Consolidated Financial Statements	F-9
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Arch Coal, Inc s internal control over financial reporting as of December 31, 2007, 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 included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Arch Coal, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007 of Arch Coal, Inc. and our report dated February 28, 2008, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 28, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at 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. at December 31, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company changed its methods of accounting for share-based payments and 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. As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for uncertainty in income taxes effective January 1, 2007.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Arch Coal, Inc. s internal control over financial reporting as of December 31, 2007, 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 28, 2008, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 28, 2008

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.

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, 2007.

The Company s independent registered public accounting firm, Ernst & Young LLP, has issued an audit report on the Company s internal control over financial reporting.

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

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CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	2007	2006	2005
	(In thousands, except per share data)		
REVENUES			
Coal sales	$ 2,413,644	$ 2,500,431	$ 2,508,773
COSTS, EXPENSES AND OTHER			
Cost of coal sales	1,888,285	1,909,822	2,174,007
Depreciation, depletion and amortization	242,062	208,354	212,301
Selling, general and administrative expenses	84,446	75,388	91,568
Other operating (income) expense:			
Gain on sale of Powder River Basin assets			(46,547)
Gain on sale of Central Appalachian operations			(7,528)
Other operating (income) expense, net	(30,766)	(29,800)	7,115
	2,184,027	2,163,764	2,430,916
Income from operations	229,617	336,667	77,857
Interest expense, net:			
Interest expense	(74,865)	(64,364)	(72,409)
Interest income	2,600	3,725	9,289
	(72,265)	(60,639)	(63,120)
Other non-operating expense:			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps	(1,919)	(4,836)	(7,740)
Other non-operating expense	(354)	(2,611)	(3,524)
	(2,273)	(7,447)	(11,264)
Income before income taxes	155,079	268,581	3,473
Provision for (benefit from) income taxes	(19,850)	7,650	(34,650)
NET INCOME	174,929	260,931	38,123
Preferred stock dividends	(219)	(378)	(15,579)
Net income available to common stockholders	$ 174,710	$ 260,553	$ 22,544
EARNINGS PER COMMON SHARE			
Basic earnings per common share	$ 1.23	$ 1.83	$ 0.18
Diluted earnings per common share	$ 1.21	$ 1.80	$ 0.17
Basic weighted average shares outstanding	142,518	142,770	127,304

Diluted weighted average shares outstanding	144,019	144,812	129,940
Dividends declared per common share	$ 0.27	$ 0.22	$ 0.16

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

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CONSOLIDATED BALANCE SHEETS

	December 31 2007	2006
	(In thousands, except per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,080	$ 2,523
Trade accounts receivable	229,965	212,185
Other receivables	19,724	48,588
Inventories	177,785	129,826
Prepaid royalties	22,055	6,743
Deferred income taxes	18,789	51,802
Other	47,747	35,610
Total current assets	521,145	487,277
Property, plant and equipment:		
Coal lands and mineral rights	1,690,176	1,587,303
Plant and equipment	1,729,501	1,626,984
Deferred mine development	672,496	550,385
	4,092,173	3,764,672
Less accumulated depreciation, depletion and amortization	(1,628,535)	(1,521,604)
Property, plant and equipment, net	2,463,638	2,243,068
Other assets:		
Prepaid royalties	105,106	112,667
Goodwill	40,032	40,032
Deferred income taxes	296,559	263,759
Equity investments	82,950	80,213
Other	85,169	93,798
Total other assets	609,816	590,469
Total assets	$ 3,594,599	$ 3,320,814
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 150,026	$ 198,875
Accrued expenses	188,875	190,746
Current maturities of debt and short-term borrowings	217,614	51,185
Total current liabilities	556,515	440,806

Long-term debt	1,085,579	1,122,595
Accrued postretirement benefits other than pension	59,181	49,817
Asset retirement obligations	219,991	205,530
Accrued workers compensation	41,071	43,655
Other noncurrent liabilities	100,576	92,817
Total liabilities	2,062,913	1,955,220
Stockholders equity:		
Preferred stock, $0.01 par value, 10,000 shares authorized; issued and outstanding shares 85 and 144, at December 31, 2007 and 2006, respectively; $50 liquidation preference	1	2
Common stock, $0.01 par value, authorized 260,000 shares, issued 143,158 and 142,179 shares, respectively	1,436	1,426
Paid-in capital	1,358,695	1,345,188
Retained earnings	173,186	38,147
Accumulated other comprehensive loss	(1,632)	(19,169)
Total stockholders equity	1,531,686	1,365,594
Total liabilities and stockholders equity	$ 3,594,599	$ 3,320,814

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

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Three Years Ended December 31, 2007

	Preferred Stock	Common Stock	Paid-In Capital	Retained Earnings (Deficit)	Unearned Compensation	Treasury Stock at Cost	Accumulated Other Comprehensive Loss	Total
	(In thousands, except per share data)							
BALANCE AT January 1, 2005	$ 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 shares of treasury stock as contribution to pension plan		3	12,872			3,857		16,732
Issuance of 3,038 shares of common stock under the stock incentive plan stock options, including income tax benefits		15	43,564					43,579
Employee stock-based compensation expense			140		12,781			12,921
Issuance of 680 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 shares of treasury stock and 182 shares of common stock to pension plan		3	15,407			1,190		16,600
Issuance of 127 shares of common stock under the stock incentive plan restricted stock and restricted stock units								
Issuance of 30 shares of common stock upon conversion of preferred stock								
Effect of two for one stock split		716		(716)				
Issuance of 661 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 shares of common stock under stock repurchase program						(43,877)		(43,877)
Retirement of treasury stock		(16)	(43,861)			43,877		
				(26,061)				(26,061)

Effect of adoption of EITF 04-6							
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
Comprehensive income:							
Net income				174,929			174,929
Pension, postretirement and other post-employment benefits						11,070	11,070
Net amount reclassified to income						2,490	2,490
Unrealized losses on available-for- sale securities						(2,815)	(2,815)
Unrealized gains on derivatives						1,584	1,584
Net amount reclassified to income						5,208	5,208
Total comprehensive income							192,466
Dividends:							
Common ($0.27 per share)				(38,696)			(38,696)
Preferred ($2.50 per share)				(219)			(219)
Issuance of 186 shares of common stock under the stock incentive plan restricted stock and restricted stock units		2	(2)				
Issuance of 283 shares of common stock upon conversion of preferred stock	(1)	3	(2)				
Issuance of 510 shares of common stock under the stock incentive plan stock options including income tax benefits		5	7,734				7,739
Employee stock-based compensation expense			5,777				5,777
Effect of adoption of FIN 48				(975)			(975)

BALANCE AT DECEMBER 31, 2007	$	1	$	1,436	$	1,358,695	$	173,186	$		$		$	(1,632)	$	1,531,686

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2007	2006	2005
	(In thousands)		
OPERATING ACTIVITIES			
Net income	$ 174,929	$ 260,931	$ 38,123
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	242,062	208,354	212,301
Prepaid royalties expensed	11,962	9,045	14,252
Net (gain) loss on dispositions of property, plant and equipment	(17,769)	649	(82,168)
Gain on investment in Knight Hawk Holdings, LLC		(10,309)	
Employee stock-based compensation	5,777	9,080	12,937
Other non-operating expense	2,273	7,447	11,264
Changes in operating assets and liabilities:			
Receivables	10,254	(49,265)	(48,432)
Inventories	(55,471)	(39,783)	(38,368)
Accounts payable and accrued expenses	(59,634)	(115,123)	108,536
Income taxes	(31,825)	20,505	(33,513)
Accrued postretirement benefits other than pension	3,733	8,662	28,660
Asset retirement obligations	21,609	10,967	6,498
Accrued workers compensation	971	(2,898)	(9,705)
Other			14,701
Other	21,939	(10,160)	19,521
Cash provided by operating activities	330,810	308,102	254,607
INVESTING ACTIVITIES			
Capital expenditures	(488,363)	(623,187)	(357,142)
Proceeds from dispositions of property, plant and equipment	70,296	777	117,048
Additions to prepaid royalties	(19,713)	(20,062)	(28,164)
Purchases of investments/advances to affiliates	(5,540)	(45,533)	(23,285)
Reimbursement of deposit on equipment	18,325		
Cash used in investing activities	(424,995)	(688,005)	(291,543)
FINANCING ACTIVITIES			
Net proceeds from commercial paper and net borrowings on lines of credit	133,476	192,300	(25,000)
Net proceeds from (payments on) other debt	(2,696)	442	(2,376)
Debt financing costs	(202)	(2,171)	(2,662)
Dividends paid	(38,945)	(31,815)	(27,639)
Purchases of treasury stock		(43,876)	
Issuance of common stock under incentive plans	5,109	7,045	31,947
Cash provided by (used in) financing activities	96,742	121,925	(25,730)

Increase (decrease) in cash and cash equivalents		2,557		(257,978)		(62,666)
Cash and cash equivalents, beginning of year		2,523		260,501		323,167
Cash and cash equivalents, end of year	$	5,080	$	2,523	$	260,501
SUPPLEMENTAL CASH FLOW INFORMATION:						
Cash paid during the year for interest	$	69,866	$	59,116	$	69,839
Cash received during the year for income taxes	$	(2,145)	$	(8,921)	$	(5,518)

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

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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 located 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.

The Company owns a 99% membership 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.

On June 29, 2007, the Company sold select assets and related liabilities associated with its Mingo Logan-Ben Creek mining complex in West Virginia. See further discussion in Note 2, Property Transactions.

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 three of its subsidiaries and their Central Appalachian mining operations. See further discussion in Note 2, Property Transactions.

Accounting Pronouncements Adopted

On January 1, 2007, the Company adopted Financial Accounting Standards Board (FASB) 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. Under FIN 48, a company can recognize the benefit of an income tax position only if it is more likely than not (greater than 50%) that the tax position will be sustained upon tax examination, based solely on the technical merits of the tax position.

Upon adoption of FIN 48, the Company increased its liability for unrecognized tax benefits by $1.0 million, including interest and penalties of $0.2 million, which was recorded as a reduction of the beginning balance of retained earnings. Total unrecognized tax benefits were $3.2 million at the adoption date, all of which would affect the effective tax rate if recognized. The Company will continue to recognize interest and penalties related to income tax matters in income tax expense.

Accounting Estimates

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

Cash and Cash Equivalents

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

Allowance for Uncollectible Receivables

The Company s allowance for uncollectible receivables reflects the amounts of its trade accounts receivable and other receivables that are not expected to be collected, based on past collection history, the economic

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The allowance deducted from the balance of receivables was $0.2 million and $3.2 million at December 31, 2007 and 2006, respectively.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs, transportation costs prior to title transfer to customers and operating overhead. Prior to the adoption of Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs in the Mining Industry* (EITF 04-6), 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. As a result of the adoption of EITF 04-6 on January 1, 2006, stripping costs incurred during the production phase of the mine are considered variable production costs and are included in the cost of inventory extracted during the period the stripping costs are incurred. 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.

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 and deferred taxes.

Prepaid Royalties

Rights to leased coal lands are often acquired through royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as a prepaid asset, with amounts expected to be recouped within one year classified as current. 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 over the tons of coal shipped during the term of the contract. Value is allocated to coal supply agreements based on discounted cash flows attributable to the difference between the contract price and the prevailing market price at the date of acquisition. The net book value of the Company s above-market coal supply agreements was $3.5 million and $3.8 million at December 31, 2007 and 2006, respectively. These amounts are recorded in other current assets and other assets in the accompanying Consolidated Balance Sheets. The net book value of the below-market coal supply agreements was $1.3 million and $3.2 million at December 31, 2007 and 2006, respectively. These amounts are recorded in accrued expenses and other noncurrent liabilities in the accompanying Consolidated Balance Sheets. Amortization expense on all above-market coal supply agreements was $0.3 million, $1.0 million and $8.0 million in 2007, 2006 and 2005, respectively. Amortization income on all below-market coal supply agreements was $1.9 million, $11.8 million and $16.0 million in 2007, 2006 and 2005, respectively.

Exploration Costs

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007, 2006 and 2005, interest costs of $18.0 million, $14.8 million and $4.2 million, respectively, were capitalized. Expenditures that 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. Costs may include construction permits and licenses; mine design; construction of access roads, shafts, slopes and main entries; and removing overburden to access reserves in a new pit. Additionally, deferred mine development includes the costs associated with asset retirement obligations.

Coal Lands and Mineral Rights

Amounts paid to acquire the Company s coal reserves are capitalized and depleted over the life of proven and probable reserves. A significant portion of the Company s coal reserves are controlled through leasing arrangements. The cost of 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 $1.0 billion and $954.2 million at December 31, 2007 and 2006, 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 second and third installments of $122.2 million in 2006 and 2007, with the two remaining annual payments to be paid in 2008 and 2009. These payments are capitalized as the cost of the underlying mineral reserves.

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 when 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $20.2 million and $24.8 million at December 31, 2007 and 2006, respectively. These amounts are recorded in other assets in the accompanying Consolidated Balance Sheets. Amounts classified as current were $4.7 million and $4.6 million at December 31, 2007 and 2006, respectively. These amounts are recorded in other current assets in the accompanying Consolidated Balance Sheets.

Revenue Recognition

Coal sales revenues include sales to customers of coal produced at Company operations and coal purchased from third parties. The Company recognizes revenue from coal sales at the time risk of loss passes to the customer 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; income from equity investments; gains and losses from dispositions of long-term assets; and 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 corresponding amount is capitalized as part of the carrying amount of the related long-lived asset. Amortization of the related asset is recorded on a units-of-production basis over the mine s estimated recoverable reserves. See additional discussion in Note 11, Asset Retirement Obligations.

Derivative Financial Instruments

The Company generally has used derivative financial instruments to manage exposures to commodity prices and interest rates. Additionally, the Company may hold certain coal derivative financial instruments for trading purposes.

All derivative financial instruments are recognized in the balance sheet at fair value. Changes in fair value are recognized in earnings if the derivatives 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. The Company formally documents the relationships between hedging instruments and the respective hedged items, as well as its risk management objectives for undertaking various hedge transactions. The Company evaluates the effectiveness of its hedging relationships both at the hedge inception and on an ongoing basis.

Any ineffective portion of a cash flow hedge s change in fair value is recognized immediately in earnings. The amount of ineffectiveness recognized in other operating (income) expense, net in the accompanying

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Consolidated Statements of Income relating to our heating oil derivatives was a gain of $1.4 million for the year ended December 31, 2007. The amount of ineffectiveness relating to interest rate swaps recognized in other non-operating expense in the accompanying Consolidated Statements of Income was a loss of $1.0 million for the year ended December 31, 2005. Ineffectiveness was insignificant for the year ended December 31, 2006.

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. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. In determining the appropriate valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies and its overall deferred tax position.

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 also currently provides certain postretirement medical and life insurance coverage for eligible employees. Costs of providing benefits are determined on an actuarial basis and accrued over the employee s period of active service.

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 12 and 13 for additional disclosures relating to these obligations.

The Company has an obligation under the Coal Industry Retiree Health Benefit Act of 1992 (Benefit Act), which provides for the funding of medical and death benefits for certain retired members of the United Mine Workers of America (UMWA) through premiums 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.

Stock-Based Compensation

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 adoption date forward. 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. The effects of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adoption on retained earnings, net income and the Consolidated Statement of Cash Flows for the year ended December 31, 2006 were insignificant. See further discussion in Note 16, Stock Based Compensation and Other Incentive Plans.

Accounting Standards Issued and Not Yet Adopted

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 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 FASB deferred the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The Company does not expect adoption of Statement No. 157 to have a material impact on the Company s financial position or results of operations.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Liabilities Including an amendment of FASB Statement No. 115* (Statement No. 159). Statement No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Statement No. 159 is effective prospectively for fiscal years beginning after November 15, 2007. The Company does not expect adoption of Statement No. 159 to have a material impact on the Company s financial position or results of operations.

2. Property Transactions

On September 28, 2007, the Company purchased coal reserves and surface rights in Illinois for $38.9 million. This property is adjacent to other properties owned by the Company and includes approximately 157 million tons of recoverable coal reserves. Of the total recoverable tons, approximately 134 million tons are owned, with the remainder controlled under long-term leases.

On June 29, 2007, the Company sold select assets and related liabilities associated with its Mingo Logan-Ben Creek mining complex in West Virginia for $43.5 million. For the years ended December 31, 2007, 2006 and 2005, the Company s Mingo Logan-Ben Creek operations contributed coal sales of 1.2 million, 4.0 million and 4.7 million tons, revenues of $75.1 million, $243.8 million and $261.5 million and income from operations of $9.1 million, $19.5 million and $15.2 million, respectively.

The Company recognized a net gain of $8.9 million in the year ended December 31, 2007 resulting from the sale of the Mingo Logan-Ben Creek complex. That amount has been reflected in other operating (income) expense, net in the accompanying Consolidated Statements of Income. This gain is net of accrued losses of $12.5 million on firm commitments to purchase coal through 2008 to supply below-market sales contracts that can no longer be sourced from the Company s operations and $4.9 million of employee-related payments, which were paid prior to December 31, 2007.

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, Inc., 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 year ended December 31, 2005, collectively, these subsidiaries sold 12.7 million tons of coal, had revenues of $509.8 million and incurred losses from operations of $8.3 million. As a result of the sale, Magnum acquired all of the assets and liabilities of the subsidiaries including various employee liabilities of idle union properties whose former employees were signatory to a UMWA contract.

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 13, 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. As of December 31, 2007 and 2006, the Company had a current receivable due from Magnum of $1.1 million and $8.5 million, respectively, 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 20, Guarantees.

On December 30, 2005, the Company completed a reserve swap with Peabody Energy Corp. (Peabody) and sold to Peabody a rail spur, rail loadout and an idle office complex located in the Powder River Basin for a purchase price of $84.6 million. In the reserve swap, the Company exchanged 60.0 million tons of its coal reserves for a similar block of 60.0 million tons of coal reserves held by 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 September 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 19, Leases.

During the years ended December 31, 2007, 2006 and 2005, gains (losses) on other dispositions of property, plant and equipment were $8.9 million, $(0.6) million and $28.2 million, respectively. Included in the gain for 2007 was a gain of $8.4 million on the sales of non-strategic reserves in the Powder River Basin and Central Appalachia. Included in the gain for 2005 was a gain of $9.0 million on the sale of surface land rights at

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

3. 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, 2005	$ (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)
2007 activity, before tax	9,533		21,183	(4,398)	26,318
2007 activity, tax effect	(2,741)		(7,623)	1,583	(8,781)
Balance December 31, 2007	$ 280	$	$ (842)	$ (1,070)	$ (1,632)

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. Pension, postretirement and other post-employment benefits adjustments relate to changes in the funded status of various benefit plans, as discussed in Note 1, Accounting Policies. The unrealized gains and losses on recording the Company s available-for-sale securities at fair value are recorded through other comprehensive income.

4. Investments

On July 31, 2006, the Company acquired a 331/3% 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 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) expense, 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 $3.6 million and $2.1 million for the years ended December 31, 2007 and 2006, respectively. At December 31, 2007 and 2006, the Company had an investment in Knight Hawk of $43.9 million and $41.9 million, respectively.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

value for two additional coal-to-liquids projects outside of the Carbon Basin, and to invest $25.0 million in DKRW. In March 2007, DKRW issued additional interests of $25.0 million, of which the Company purchased $3.7 million. This transaction lowered the Company s equity interest to 24%. The Company s portion of DKRW s loss was $1.6 million and $0.1 million for the years ended December 31, 2007 and 2006, respectively. At December 31, 2007 and 2006, the Company had an investment in DKRW of $26.9 million and $24.9 million, respectively.

The Company holds a 17.5% general partnership interest in Dominion Terminal Associates (DTA), which is accounted for on the equity method. DTA operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia used by the partners to transload coal. Financing for the facility was provided through $132.8 million of tax-exempt bonds issued by Peninsula Ports Authority of Virginia (PPAV). DTA leases the facility from PPAV for amounts sufficient to meet debt-service requirements. The Company retired its 17.5% share, or $23.2 million, of the bonds in the fourth quarter of 2005. Under the terms of a throughput and handling agreement with DTA, each partner is charged its share of cash operating and debt-service costs in exchange for the right to use the facility s loading capacity and is required to make periodic cash advances to DTA to fund such costs. The Company s portion of DTA s costs was $3.1 million, $2.0 million and $3.4 million for the years ended December 31, 2007, 2006 and 2005, respectively. At December 31, 2007 and 2006, the Company had an investment in DTA of $12.1 million and $13.4 million, respectively.

The fair value of investments in stock and other equity interests not accounted for under the equity method of accounting totaled $1.9 million and $6.6 million at December 31, 2007 and 2006, respectively.

5. Inventories

Inventories consist of the following:

	December 31 2007	2006
	(In thousands)	
Coal	$ 61,656	$ 49,608
Repair parts and supplies	116,129	80,218
	$ 177,785	$ 129,826

The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $13.5 million and $15.4 million at December 31, 2007 and 2006, respectively.

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.

6. Derivative Financial Instruments

Diesel fuel price risk management

The Company is exposed to price risk with respect to diesel fuel purchased for use in its operations. 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 purchases being hedged. 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, 2007, the Company held heating oil swaps and purchased call options protecting approximately 23% of its purchases for fiscal year 2008. The fair value of these positions was a current asset of $2.0 million at December 31, 2007 and a current asset of $0.4 million and a currently liability of $5.5 million at December 31, 2006.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Coal trading positions

The Company may sell or purchase forward contracts and options in the over-the-counter coal market for trading purposes. The Company recorded an asset for the fair value of these positions of $8.5 million at December 31, 2007. The timing of the estimated future realization of the value of the trading portfolio is 30% in 2008, 68% in 2009 and 2% in 2010. The Company had no trading positions outstanding at December 31, 2006.

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 year ended December 31, 2005, the Company recognized $2.3 million of unrealized losses related to these swaps. For the years ended December 31, 2007, 2006 and 2005, the Company recognized $1.9 million, $4.8 million and $7.7 million of expense, respectively, related to the amortization of the balance in other comprehensive income.

7. Accrued Expenses

Accrued expenses included in current liabilities consist of the following:

	December 31	
	2007	2006
	(In thousands)	
Payroll and employee benefits	$ 48,990	$ 50,741
Taxes other than income taxes	77,810	73,235
Workers compensation	6,973	7,844
Interest	33,478	33,151
Asset retirement obligations	4,530	11,111
Other accrued expenses	17,094	14,664
	$ 188,875	$ 190,746

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Income Taxes

The Company is subject to U.S. federal income tax as well as income tax in multiple state jurisdictions. The tax years 1998 and 2003 through 2007 remain open to examination for U.S. federal income tax matters and 2003 through 2007 remain open to examination for various state income tax matters.

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

	Year Ended December 31		
	2007	2006	2005
	(In thousands)		
Current:			
Federal	$ 3,687	$ 1,213	$ (13,703)
State			
Total current	3,687	1,213	(13,703)
Deferred:			
Federal	(20,090)	22,700	(22,843)
State	(3,447)	(16,263)	1,896
Total deferred	(23,537)	6,437	(20,947)
	$ (19,850)	$ 7,650	$ (34,650)

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:

	Year Ended December 31		
	2007	2006	2005
	(In thousands)		
Income tax expense at statutory rate	$ 54,278	$ 94,003	$ 1,216
Percentage depletion allowance	(36,028)	(38,754)	(34,752)
State taxes, net of effect of federal taxes	569	1,576	(3,805)
Change in valuation allowance	(38,681)	(49,129)	(6,138)
Termination of interest rate swaps			5,049
Other, net	12	(46)	3,780
	$ (19,850)	$ 7,650	$ (34,650)

In 2007 and 2006, compensatory stock options and other equity based compensation awards were exercised resulting in a tax benefit of $5.6 million and $7.7 million, respectively that will be recorded 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 2006, the tax effect of the adoption of EITF 04-6 relating to the accounting for advanced stripping costs was a $16.7 million benefit that was recorded to retained earnings.

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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	
	2007	2006
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 154,222	$ 179,705
Plant and equipment	104,774	103,906
Alternative minimum tax credit carryforwards	98,900	86,148
Reclamation and mine closure	42,790	38,314
Workers compensation	19,633	20,245
Advance royalties	17,766	16,816
Postretirement benefits other than pension	16,357	15,689
Other	58,094	74,337
Gross deferred tax assets	512,536	535,160
Valuation allowance	(69,326)	(114,034)
Total deferred tax assets	443,210	421,126
Deferred tax liabilities:		
Deferred development	57,884	28,055
Investment in tax partnerships	56,209	57,917
Other	13,769	19,593
Total deferred tax liabilities	127,862	105,565
Net deferred tax asset	315,348	315,561
Less current asset	18,789	51,802
Long-term deferred tax asset	$ 296,559	$ 263,759

The Company has net operating loss carryforwards for regular income tax purposes of $154.2 million at December 31, 2007 that will expire from 2008 to 2027. The Company has an alternative minimum tax credit carryforward of $98.9 million at December 31, 2007, 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 $44.7 million during 2007 and $49.1 million during 2006, due to a change in management s assessment of the ability of the Company to realize its deferred tax assets. Of the 2007 decrease, $2.6 million was allocated to paid in capital associated with the exercise of compensatory stock options. Of the total valuation allowance at December 31, 2007, $3.9 million pertains to deferred tax benefits associated with the exercise of compensatory stock options and will be allocated to paid in capital when recognized.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A reconciliation of the beginning and ending amounts of gross unrecognized tax benefits is as follows (in thousands):

Balance at January 1, 2007	$ 3,207
Additions based on tax positions related to the current year	1,255
Additions for tax positions of prior years	133
Reductions for tax positions of prior years	(284)
Settlements	(241)
Balance at December 31, 2007	$ 4,070

If recognized, $3.3 million of the gross unrecognized tax benefits at December 31, 2007 would affect the effective tax rate. Gross unrecognized tax benefits totaling $2.2 million are expected to be reduced in the next 12 months due to the expiration of the statute of limitations.

The Company s treatment of the 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 is currently under review by the IRS. The Company has recognized a deferred tax asset related to its investment in Arch Western under FIN 48, but the outcome of the review could result in adjustments to the basis of the partnership assets. The outcome of the negotiations is uncertain, however, it is possible the Company could be required to decrease its deferred income tax assets in an amount up to $25.0 million.

9. Debt and Financing Arrangements

Debt consists of the following:

	December 31	
	2007	2006
	(In thousands)	
Commercial paper	$ 74,959	$
Indebtedness to banks under credit facilities, expiring in 2011	250,816	192,300
6.75% senior notes ($950.0 million face value) due July 1, 2013	957,514	958,881
Promissory note due 2009	8,450	11,624
Other	11,454	10,975
	1,303,193	1,173,780
Less current maturities	217,614	51,185
Long-term debt	$ 1,085,579	$ 1,122,595

On August 15, 2007, the Company entered into a commercial paper placement program, as amended, to provide short-term financing at rates that are generally lower than the rates available under the revolving credit facility. Under the program, the Company may sell up to $75.0 million in interest-bearing or discounted short-term unsecured debt obligations with maturities of no more than 270 days. The commercial paper placement program is supported by a $75.0 million revolving credit facility with a maturity date of June 7, 2008. As of December 31, 2007, the weighted-average interest rate of the Company s outstanding commercial paper was 5.08% and maturity dates ranged from 2 to 81 days.

The Company has a secured revolving credit facility that allows for up to $800.0 million in borrowings. 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. The Company s credit facility is secured by substantially all of its assets as well as its ownership interests in substantially all of its subsidiaries, except its ownership interests in Arch Western and its subsidiaries. As of December 31, 2007 and

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2006, borrowings of $160.0 million and $103.1 million, respectively, were outstanding under the credit facility. At December 31, 2007, the Company had $640.0 million of unused borrowings under the revolver. As of December 31, 2007, the weighted-average interest rate of the Company s outstanding borrowings under the credit facility was 6.30%. Commitment fees, ranging from 0.20% to 0.375% per annum, are payable on the average unused daily balance of the revolving credit facility. Financial covenant requirements may restrict the amount of unused capacity available to the Company for borrowings and letters of credit. As of December 31, 2007, the Company was not restricted by financial covenants.

On February 10, 2006, the Company established an accounts receivable securitization program of up to $150.0 million that expires on February 3, 2011, as amended. 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 vary with our leverage ratio, as defined in the amendment. The average cost of borrowing in effect as of December 31, 2007 was 5.79%. As of December 31, 2007 and 2006, borrowings of $90.8 million and $89.2 million, respectively, were outstanding under the program. At December 31, 2007, the Company had no available borrowing capacity under the program.

The senior notes were issued by the Company s subsidiary, Arch Western Finance LLC (Arch Western Finance), under an indenture dated June 25, 2003. The senior notes are guaranteed by Arch Western and certain of its subsidiaries and are secured by a security interest in loans made to Arch Coal by Arch Western. The terms of the senior notes contain restrictive covenants that limit Arch Western s ability to, among other things, incur additional debt, sell or transfer assets, and make certain investments. Arch Western Finance issued $250.0 million of the Senior Notes at a premium of 104.75% of par. The premium is being amortized over the life of the bonds.

The promissory note was discounted at its issuance to its present value using a rate of 7.0%. The face amount of the promissory note of $9.0 million at December 31, 2007 is payable in quarterly installments of $1.0 million through July 2008 and $1.5 million from October 2008 through July 2009.

Aggregate maturities of debt are $217.6 million in 2008, $4.4 million in 2009, $0 in 2010, $123.7 million in 2011, $0 in 2012 and $957.5 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. The terms also 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, 2007.

10. 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, 2007 and 2006, the carrying amounts of cash and cash equivalents approximate fair value.

Investments: See Note 4, Investments for the fair value of investments in stock and other equity interests.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt: At December 31, 2007 and 2006, the fair value of the Company s senior notes and other long-term debt, including amounts classified as current, was $1,276.9 million and $1,165.4 million, respectively.

Derivatives: See Note 6, Derivative Financial Instruments for the fair value of the Company s derivative instruments.

11. Asset Retirement Obligations

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

The Company 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 obligations for the years ended December 31:

	2007	2006
	(In thousands)	
Balance at January 1 (including current portion)	$ 216,641	$ 177,408
Accretion expense	18,585	15,426
Reductions resulting from property disposals	(6,897)	
Adjustments to the liability from changes in estimates	(945)	27,834
Liabilities settled	(2,863)	(4,027)
Balance at December 31	224,521	216,641
Current portion included in accrued expenses	(4,530)	(11,111)
Noncurrent liability	$ 219,991	$ 205,530

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, 2007, the Company had $171.1 million in surety bonds outstanding and $306.4 million in self-bonding to secure reclamation obligations.

12. 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. The occupational disease benefit obligation is 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.

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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		
	2007	2006	2005
	(In thousands)		
Self-insured occupational disease benefits:			
Service cost	$ 1,310	$ 1,014	$ 1,159
Interest cost	998	959	1,852
Net amortization	(1,688)	(1,952)	(3,793)
Total occupational disease	620	21	(782)
Traumatic injury claims and assessments	10,055	8,552	20,196
Total workers compensation expense	$ 10,675	$ 8,573	$ 19,414

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	
	2007	2006
	(In thousands)	
Beginning of year obligation	$ 19,035	$ 16,907
Service cost	1,310	1,014
Interest cost	998	959
Actuarial (gain) loss	(3,558)	560
Benefit and administrative payments	(322)	(405)
Net obligation at end of year	$ 17,463	$ 19,035

At December 31, 2007 and 2006, accumulated gains of $9.1 million and $7.3 million, respectively, were not yet recognized in occupational disease cost and were recorded in accumulated other comprehensive income. The accumulated gain that will be amortized from accumulated other comprehensive income into occupational disease cost in 2008 is $1.4 million.

The following table provides the assumptions used to determine the projected occupational disease obligation:

	Year Ended December 31		
	2007	**2006**	**2005**
Weighted average assumptions:			
Discount rate	6.50%	5.90%	5.80%
Cost escalation rate	3.00%	3.00%	3.00%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31	
	2007	2006
	(In thousands)	
Occupational disease costs	$ 17,463	$ 19,035
Traumatic and other workers compensation claims	30,581	32,464
Total obligations	48,044	51,499
Less amount included in accrued expenses	6,973	7,844
Noncurrent obligations	$ 41,071	$ 43,655

As of December 31, 2007, the Company had $61.0 million in surety bonds and letters of credit outstanding to secure workers compensation obligations.

13. Employee Benefit Plans

Defined Benefit Pension and Other Postretirement Benefit Plans

The Company has funded and unfunded 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 2 Property Transactions. The settlement resulted in an expense of $3.2 million during the year ended December 31, 2006, of which $1.9 million 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 and 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 benefit plans are contributory, with retiree contributions adjusted annually, 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 benefits as they are paid.

During 2007, the postretirement benefit plans were amended to improve benefits to participants. As a result of the amendment, annual retiree contribution increases have been limited so as not to exceed 25% of the previous year s total contribution. Prior to the amendment, all medical cost increases were passed on to the retirees and had no impact on the plan.

During 2005, the postretirement benefit plans were amended to improve benefits to participants. In addition, as discussed in Note 2, Property Transactions, the Company sold three of its subsidiaries with operations in Central Appalachia on December 31, 2005, along with the related postretirement benefit obligations. This disposition constituted a settlement of the Company s postretirement benefit obligation and a loss of $59.2 million was recognized.

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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	
	2007	2006	2007	2006
	(In thousands)			
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligations at January 1	$ 231,234	$ 234,635	$ 53,242	$ 65,034
Service cost	12,791	9,676	2,796	4,673
Interest cost	13,197	12,806	3,050	3,609
Plan amendments			8,787	
Settlements		(28,887)		
Benefits paid	(13,281)	(4,471)	(2,776)	(1,432)
Other-primarily actuarial (gain) loss	(9,313)	7,475	(3,157)	(18,642)
Benefit obligations at December 31	$ 234,628	$ 231,234	$ 61,942	$ 53,242
CHANGE IN PLAN ASSETS				
Value of plan assets at January 1	$ 216,061	$ 209,974	$	$
Actual return on plan assets	27,382	20,124		
Settlements		(28,887)		
Employer contributions	2,706	19,321	2,776	1,432
Benefits paid	(13,281)	(4,471)	(2,776)	(1,432)
Value of plan assets at December 31	$ 232,868	$ 216,061	$	$
Accrued benefit cost	$ (1,760)	$ (15,173)	$ (61,942)	$ (53,242)
ITEMS NOT YET RECOGNIZED AS A COMPONENT OF NET PERIODIC BENEFIT COST				
Prior service credit (cost)	$ (232)	$ 36	$ (22,074)	$ (14,950)
Accumulated gain (loss)	(3,390)	(29,959)	15,261	15,121
	$ (3,622)	$ (29,923)	$ (6,813)	$ 171
BALANCE SHEET AMOUNTS				
Noncurrent asset	$ 7,307	$	$	$
Current liability	$ (538)	$ (673)	$ (2,761)	$ (3,425)
Noncurrent liability	$ (8,529)	$ (14,500)	$ (59,181)	$ (49,817)
	$ (1,760)	$ (15,173)	$ (61,942)	$ (53,242)

Pension Benefits

The accumulated benefit obligation for all pension plans was $223.3 million and $220.3 million at December 31, 2007 and 2006, respectively. The accumulated benefit obligation differs from the benefit obligation in that it includes no assumption about future compensation levels.

The benefit obligation and the accumulated benefit obligation for the Company s unfunded pension plan were $9.1 million and $8.3 million, respectively, at December 31, 2007.

The prior service credit and net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2008 are $(0.2) million and $2.5 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2008 are $3.5 million and $(3.1) 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.

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

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
			(In thousands)			
Service cost	$ 12,791	$ 9,676	$ 11,072	$ 2,796	$ 4,673	$ 5,592
Interest cost	13,197	12,806	12,655	3,050	3,609	31,866
Expected return on plan assets*	(17,324)	(16,256)	(15,944)			
Amortization of prior service cost (credit)	(269)	(294)	(313)	1,663	1,547	(479)
Amortization of other actuarial losses (gains)	7,198	7,305	7,706	(3,014)	626	26,361
Settlements		3,150				59,195
Net benefit cost	$ 15,593	$ 16,387	$ 15,176	$ 4,495	$ 10,455	$ 122,535

* 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	
	2007	**2006**	**2007**	**2006**
Weighted average assumptions:				
Discount rate	6.50%	5.90%	6.50%	5.90%
Rate of compensation increase	3.39%	3.39%	N/A	N/A

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

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
Weighted average assumptions:						
Discount rate	5.90%	5.80%/6.40%	6.00%	5.90%	5.80%	6.00%
Rate of compensation increase	3.39%	3.50%	3.50%	N/A	N/A	N/A
Expected return on plan assets	8.50%	8.25%	8.50%	N/A	N/A	N/A

Due to the pension plan settlement in 2006 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2008, the Company will utilize an expected rate of return of 8.50%.

The health care cost trend rate assumed for 2008 is 13% and is expected to reach an ultimate trend rate of 5% by the year 2014. A one-percentage-point increase in the health care cost trend rate would have increased the postretirement benefit obligation at December 31, 2007 by $1.4 million. A one-percentage-point decrease in the health care cost trend rate would have decreased the postretirement benefit obligation at December 31, 2007 by $0.6 million. The effect of these changes would have had an insignificant impact on the net periodic postretirement benefit costs

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

	December 31 2007	December 31 2006
Equity securities	73%	72%
Debt securities	23%	23%
Cash and equivalents	4%	5%
Total	100%	100%

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

Cash Flows. The Company expects to make contributions of $2.5 million to its pension plans in 2008.

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

	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2008	$ 16,360	$ 2,763
2009	17,950	4,400
2010	19,633	4,748
2011	20,719	5,139
2012	22,518	5,447

Years 2013-2017	126,197	31,690
	$ 223,377	$ 54,187

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

tax on coal production) commencing in 1995. Since the sale of the Central Appalachia operations sold in the fourth quarter of 2005 to Magnum, the Company reimburses Magnum for premiums related to the retirees of those operations. 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 $1.5 million, $1.1 million and $3.4 million in the years ended December 31, 2007, 2006 and 2005, respectively, for premiums pursuant to the Benefit Act.

The Company was a party to a lawsuit against the UMWA combined benefit fund associated with the Central Appalachia operations sold in the fourth quarter of 2005. The lawsuit contested premium calculations that involved the assignment of retiree benefits by the Social Security Administration to the signatory companies. During the year ended December 31, 2007, the litigation was resolved in favor of the signatory companies to the combined benefit fund and the Company recognized income of $3.8 million, of which $3.4 million is included as a reduction in cost of coal sales and $0.4 million is included in interest income in the accompanying Consolidated Statements of Income.

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 $14.5 million, $13.4 million and $12.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

14. 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 year ended December 31, 2005 reflect the split.

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. During 2007 and 2006, 58,890 and 6,737 shares, respectively, of preferred stock were converted to common stock. On December 1, 2005, the Company issued a tender offer and accepted for conversion on December 31, 2005 2,724,418 shares of Preferred Stock which were converted to 13,308,238 shares of common stock, including a conversion premium of 0.0220 shares. The Company recognized a dividend on the Preferred Stock associated with the tender offer 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.

The Company announced in December 2007 that it would redeem on February 1, 2008 any shares of preferred stock outstanding at that date at a redemption price of $50.00 per share plus accumulated and unpaid dividends.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

common stock. At December 31, 2007, 12,437,600 million shares of common stock were available for repurchase under the plan. No purchases were made under the plan during 2007. During 2006, the Company purchased and retired 1,562,400 shares of common stock for $43.9 million at an average cost of $28.08 per share. 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.

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

16. 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, 2007, the Company had stock options, restricted stock, restricted stock units and performance contingent phantom 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, 2007:

	Common Shares (In thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In thousands)	Average Contract Life

Options outstanding at January 1	2,273	$ 10.58		
Granted	891	33.01		
Exercised	(510)	10.02		
Canceled	(8)	26.19		
Options outstanding at December 31	2,646	18.20	$ 52,554	5.91
Options exercisable at December 31	1,731	10.43	47,875	4.20

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The aggregate intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was $14.9 million, $21.2 million and $46.1 million, respectively.

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, 2007:

	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value
Unvested options at January 1	70	$ 9.94
Granted	891	14.37
Vested	(41)	8.18
Canceled	(5)	14.12
Unvested options at December 31	915	14.07

Compensation cost of stock option grants is recognized straight-line over the options vesting periods. Subsequent to adoption of Statement 123R, compensation expense related to stock options for the years ended December 31, 2007 and 2006 was $3.8 million and $1.5 million, respectively. As of December 31, 2007, there was $8.4 million of unrecognized compensation cost related to the unvested stock options. The total grant-date fair value of options vested during the years ended December 31, 2007, 2006 and 2005 was $0.3 million, $4.0 million and $5.9 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. The expected life of the option was determined based on the midpoint between the vesting date and the end of the contractual term of the option. 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.

Information regarding granted options follows:

	Year Ended December 31		
	2007	2006	2005
Weighted average grant-date fair value per share of options granted	$ 14.37	$ 13.53	$ 8.45
Assumptions (weighted average):			
Risk-free interest rate	4.70%	4.75%	3.70%
Expected dividend yield	0.7%	0.7%	0.9%
Expected volatility	39.5%	40.7%	51.1%
Expected life (in years)	6.0	5.0	5.0

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 year ended December 31, 2005, the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s net income available to common stockholders and earnings per common share would have been as follows (in thousands, except per share data):

Net income available to common stockholders, as reported	$	22,544
Add:		
Stock-based employee compensation included in reported net income, net of related tax effects		12,768
Deduct:		
Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		(16,894)
Pro forma net income available to common stockholders	$	18,418
Earnings per common share:		
Basic earnings per common share as reported	$	0.18
Basic earnings per common share pro forma		0.14
Diluted earnings per common share as reported		0.17
Diluted earnings per common share pro forma		0.14

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.

Information regarding restricted stock and restricted stock unit activity and weighted average grant-date fair value follows for the year ended December 31, 2007:

	Restricted Stock		Restricted Stock Units	
	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value
Outstanding at January 1	86	$ 26.20	250	$ 16.98
Granted	31	33.27		
Vested	(5)	31.61	(111)	17.70
Outstanding at December 31	112	27.95	139	16.41

The weighted average fair value of restricted stock granted during 2006 and 2005 was $36.73 and $23.01, respectively. The weighted average fair value of restricted stock units granted during 2006 and 2005 was $37.77 and $22.27, respectively. The total grant-date fair value of restricted stock that vested during 2007 and 2006 was $0.1 million and $0.3 million, respectively. The total grant-date fair value of restricted stock units that vested during 2007, 2006 and 2005 was $2.0 million, $1.7 million and $1.4 million, respectively. Unearned compensation of $2.0 million will be recognized over the remaining vesting period of the outstanding restricted stock and restricted stock units. The Company recognized expense of approximately $1.8 million, $2.0 million and $2.2 million related to restricted stock and restricted stock units for the years ended December 31, 2007, 2006 and 2005, 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 a

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

combination of 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. During the year ended December 31, 2007, certain of the stock price and EBITDA performance measurements were satisfied under the plan, and the Company issued 180,997 shares of common stock and paid cash of $2.6 million under the awards. As of December 31, 2007, a maximum of 252,600 remain available, and the Company expects the majority to be paid out in the first quarter of 2008. The Company recognized $1.4 million, $7.9 million and $4.5 million of expense under this award in the years ended December 31, 2007, 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.

Deferred Compensation Plan

The Company maintains a deferred compensation plan that allows eligible employees to defer receipt of compensation until the dates elected by the participant. Participants in the plan may defer up to 85% of their base salaries and up to 100% of their annual incentive awards. The plan also allows participants to defer receipt of up to 100% of the shares under any restricted stock unit or performance-contingent stock awards. The amounts deferred are invested in cash accounts that mirror the gains and losses of a number of different investment funds, including a hypothetical investment in shares of the Company s common stock. Participants are always vested in their deferrals to the plan and any related earnings. The Company has established a grantor trust to fund the obligations under the plan. The trust has purchased corporate-owned life insurance to offset these obligations. The policies are recorded at their net cash surrender values and totaled $21.5 million and $17.4 million at December 31, 2007 and 2006, respectively. The net gain recognized on these policies for the years ended December 31, 2007, 2006 and 2005 was $1.2 million, $1.9 million and $0.7 million, respectively. The participants have an unsecured contractual commitment by the Company to pay the amounts due under the plan. Any assets placed in trust by the Company to fund future obligations of the plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Under the plan, the Company credits each participant s account with the number of units equal to the number of shares or units that the participant could purchase or receive with the amount of compensation deferred under the plan on the date the participant s account is credited, based upon the fair market value of the underlying investment on that date. The amount the Company will pay will be based on the number of units credited to each participant s account, valued on the basis of the fair market value of an equivalent number of shares or units of the underlying investment on the date the payment occurs. The liability under the plan was $30.7 million at December 31, 2007 and $21.5 million at December 31, 2006. The Company s (income) expense related to changes in the value of the units credited to each participant s account was $5.7 million, $(1.5) million and $6.5 million in 2007, 2006 and 2005, respectively.

17. Risk Concentrations

Credit Risk and Major Customers

The Company has a formal written credit policy that establishes procedures to determine creditworthiness and credit limits for trade customers and counterparties in the over-the-counter coal market. Generally, credit is

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

extended based on an evaluation of the customer s financial condition. Collateral is not generally required, unless credit cannot be established. Credit losses are provided for in the financial statements and historically have been minimal.

The Company markets its coal principally to electric utilities in the United States. Sales to customers in foreign countries were $196.7 million, $162.5 million and $166.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. As of December 31, 2007 and 2006, accounts receivable from electric utilities located in the United States totaled $171.8 million and $159.7 million, respectively, or 75% and 76% of total trade receivables for 2007 and 2006, respectively.

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 2007. Approximately 73.6% of this tonnage (representing 73.6% 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 $6.59 to $91.17 per ton. Long-term contracts ranged in remaining life from one to 10 years. Some of these contracts include pricing which is above current market prices. Sales (including spot sales) to our largest customer, TVA, were $336.4 million, $317.8 million and $306.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Third-party sources of coal

The Company uses independent contractors to mine coal at certain mining complexes. The Company also purchases coal from third parties that it sells to customers. Factors beyond the Company s control could affect the availability of coal produced for or purchased by the Company. Disruptions in the quantities of coal produced for or purchased by the Company could impair its ability to fill customer orders or require it to purchase coal from other sources at prevailing market prices in order to satisfy those orders.

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. In the past, disruptions in rail service have resulted in missed shipments and production interruptions.

18. Earnings per Common Share

The following table reconciles basic and diluted weighted average shares outstanding. All share amounts for the year ended December 31, 2005 reflect the two-for-one split.

	Year Ended December 31		
	2007	2006	2005
	(In thousands)		

Basic weighted average shares outstanding	142,518	142,770	127,304
Effect of common stock equivalents under Incentive Plan	1,068	1,342	1,914
Effect of common stock equivalents arising from Preferred Stock	433	700	722
Diluted weighted average shares outstanding	144,019	144,812	129,940

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

dividends and conversion inducement, were excluded from the diluted earnings per common share calculation because their effect was anti-dilutive.

19. 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 $37.2 million in 2007, $28.8 million in 2006 and $31.8 million in 2005. In addition, the Company enters into various non-cancelable royalty lease agreements under which future minimum payments are due. Royalty expense, including production royalties, was $204.7 million, $201.1 million and $179.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Minimum payments due in future years under these agreements in effect at December 31, 2007 are as follows:

	Operating Leases	Royalties
	(In thousands)	
2008	$ 30,612	$ 22,380
2009	30,170	22,524
2010	27,302	21,902
2011	23,424	20,804
2012	18,414	4,631
Thereafter	43,981	18,833
	$ 173,903	$ 111,074

At December 31, 2007 and 2006, the Company had deferred gains of $5.2 million and $10.0 million, respectively, associated with sales of certain assets in which it has continuing involvement in the form of leases. The deferred gains are included as other current liabilities and other noncurrent liabilities in the accompanying Consolidated Balance Sheets. The remaining deferred gains will be recognized over the remaining term of the leases, as follows: $3.0 million in 2008, $1.0 million in 2009 and a total of $1.2 million from 2010 through 2012.

As of December 31, 2007, certain of the Company s lease obligations were secured by outstanding surety bonds totaling $45.2 million.

20. Guarantees

The Company has agreed to continue to provide surety bonds and letters of credit for reclamation and retiree healthcare obligations of Magnum related to the properties the Company sold to Magnum 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 to replace the obligations. If the surety bonds and letters of credit related to the reclamation obligations are not replaced by Magnum within a specified period of time, Magnum must post a letter of credit in favor of the Company in the amounts of the reclamation obligations. At December 31, 2007, the Company had $92.0 million of surety bonds related to properties sold to Magnum.

Magnum also acquired certain coal supply contracts with customers who have not consented to the assignment of the contract from the Company to Magnum. The Company has committed to purchase coal from Magnum to sell to those customers at the same price it is charging the customers for the sale. In addition, certain contracts have been assigned to Magnum, but the Company has guaranteed Magnum s performance under the contracts. The longest of the coal supply contracts extends to the year 2017. If Magnum is unable to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

supply the coal for these coal sales contracts then the Company would be required to purchase coal on the open market or supply contracts from its existing operations. At market prices effective at December 31, 2007, the cost of purchasing 15.4 million tons of coal to supply the contracts that have not been assigned over their duration would exceed the sales price under the contracts by approximately $265.7 million, and the cost of purchasing 5.0 million tons of coal to supply the assigned and guaranteed contracts over their duration would exceed the sales price under the contracts by approximately $97.4 million. The Company has also guaranteed Magnum s performance under certain operating leases, the longest of which extends through 2011. If the Company were required to perform under its guarantees of the operating lease agreements, it would be required to make $10.3 million of lease payments. As the Company does not believe that it is probable that it would have to purchase replacement coal or fulfill its obligations under the lease guarantees, no losses have been recorded in the financial statements as of December 31, 2007. 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 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 $61.0 million at December 31, 2007, which is not 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.

21. Contingencies

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

22. Segment Information

The Company has three reportable business segments, which are based on the major low-sulfur coal basins in which the Company operates. Each of these reportable business segments includes a number of mine complexes. The Company manages its coal sales by coal basin, not by individual mine complex. 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. 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 the Powder River Basin (PRB) segment, with operations in Wyoming; the Western Bituminous (WBIT) segment, with operations in Utah, Colorado and southern Wyoming; and the Central Appalachia (CAPP) segment, with operations in southern West Virginia, eastern Kentucky and Virginia.

Operating segment results for the years ended December 31, 2007, 2006 and 2005 are presented below. Results for the operating segments include all direct costs of mining. Corporate, Other and Eliminations includes

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

corporate overhead, land management, other support functions, and the elimination of intercompany transactions.

	PRB	WBIT	CAPP (In thousands)	Corporate, Other and Eliminations	Consolidated
December 31, 2007					
Coal sales	$ 1,053,516	$ 540,061	$ 820,067	$	$ 2,413,644
Income (loss) from operations	126,444	102,758	79,139	(78,724)	229,617
Total assets	1,694,786	1,948,674	769,645	(818,506)	3,594,599
Depreciation, depletion and amortization	115,136	66,299	58,219	2,408	242,062
Capital expenditures	48,141	99,282	163,125	177,815	488,363
December 31, 2006					
Coal sales	$ 1,043,373	$ 458,946	$ 998,112	$	$ 2,500,431
Income (loss) from operations	215,696	126,387	58,835	(64,251)	336,667
Total assets	1,584,483	1,841,104	857,934	(962,707)	3,320,814
Depreciation, depletion and amortization	111,350	46,530	48,789	1,685	208,354
Capital expenditures	121,736	138,631	231,311	131,509	623,187
December 31, 2005					
Coal sales	$ 756,874	$ 402,233	$ 1,349,666	$	$ 2,508,773
Income (loss) from operations	132,174	59,747	(15,830)	(98,234)	77,857
Total assets	1,333,289	1,723,744	786,091	(791,684)	3,051,440
Depreciation, depletion and amortization	106,870	33,364	70,605	1,462	212,301
Capital expenditures	30,668	77,932	235,313	13,229	357,142

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

	Year Ended December 31		
	2007	2006 (In thousands)	2005
Income from operations	$ 229,617	$ 336,667	$ 77,857
Interest expense	(74,865)	(64,364)	(72,409)
Interest income	2,600	3,725	9,289
Other non-operating expense	(2,273)	(7,447)	(11,264)
Income before income taxes	$ 155,079	$ 268,581	$ 3,473

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

23. Quarterly Financial Information (Unaudited)

Quarterly financial data for the years ended December 31, 2007 and 2006 is summarized below:

	March 31	June 30 (a)	September 30 (a)	December 31 (a)
	(In thousands, except per share data)			
2007:				
Coal sales	$ 571,349	$ 598,745	$ 599,151	$ 644,399
Gross profit	64,399	58,331	64,089	96,478
Income from operations	50,863	53,850	49,824	75,080
Net income available to common stockholders	28,680	37,483	27,227	81,320
Basic earnings per common share	0.20	0.26	0.19	0.57
Diluted earnings per common share	0.20	0.26	0.19	0.56

	March 31 (b)(c)	June 30 (b)(c)	September 30 (b)(c)(d)	December 31 (b)(c)
	(In thousands, except per share data)			
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(e)	0.43	0.49	0.35	0.56
Diluted earnings per common share(e)	0.42	0.48	0.35	0.55

(a) On June 29, 2007, the Company sold select assets and related liabilities associated with its Mingo Logan-Ben Creek mining complex in West Virginia for $43.5 million. The Company recognized a net gain of $8.1 million and $1.1 million in the second and third quarters of 2007 and a charge to earnings of $0.3 million in the fourth quarter of 2007 resulting from the sale.

(b) 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. 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 related to business interruption. The insurance recoveries are reflected as a reduction of cost of coal sales in the accompanying Consolidated Statements of Income.

(c) 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.

(d) During the third quarter of 2006, the Company acquired a 331/3% 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) 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. The per share amounts reflect the split. The sum of the quarterly earnings per common share amounts may not equal earnings 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.

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Schedule II

Arch Coal, Inc. and Subsidiaries

Valuation and Qualifying Accounts

	Balance at Beginning of Year	Additions (Reductions) Charged to Costs and Expenses	Charged to Other Accounts	Deductions(a)	Balance at End of Year
			(In thousands)		
Year ended December 31, 2007					
Reserves deducted from asset accounts:					
Other assets other notes and accounts receivable	$ 3,156	$ (1,187)	$	$ 1,753	$ 216
Current assets supplies and inventory	15,422	555	(2,122)(b)	355	13,500
Deferred income taxes	114,034	(38,681)	(3,603)(c)	2,424	69,326
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)(d)	1,625	1,777
Current assets supplies and inventory	22,976	(630)	(5,780)(d)	1,231	15,335
Deferred income taxes	163,005	(6,138)	6,296(e)		163,163

(a) Reserves utilized, unless otherwise indicated.

(b) Balance upon disposition of Mingo Logan-Ben Creek complex.

(c) Amount includes $1.0 million related to the adoption of FIN 48, which was recorded as a reduction of the beginning balance of retained earnings and $2.6 million related to the reversal of tax benefits from the exercise of employee stock options, which was recorded as paid-in capital.

(d) Balance upon disposition of Central Appalachian operations.

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

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Signatures

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

Arch Coal, Inc.

Steven F. Leer
Chairman and Chief Executive Officer
February 29, 2008

Signatures	Capacity	Date
Steven F. Leer	Chairman and Chief Executive Officer (Principal Executive Officer)	February 29, 2008
Robert J. Messey	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2008
John W. Lorson	Controller (Principal Accounting Officer)	February 29, 2008
* James R. Boyd	Director	February 29, 2008
* Frank M. Burke	Director	February 29, 2008
* John W. Eaves	President, Chief Operating Officer and Director	February 29, 2008
* Patricia F. Godley	Director	February 29, 2008
* Douglas H. Hunt	Director	February 29, 2008
* Brian J. Jennings	Director	February 29, 2008

*	Director	February 29, 2008
Thomas A. Lockhart		
*	Director	February 29, 2008
A. Michael Perry		

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Signatures	Capacity	Date
*	Director	February 29, 2008
Robert G. Potter		
*	Director	February 29, 2008
Theodore D. Sands		
*	Director	February 29, 2008
Wesley M. Taylor		

*By:

Robert G. Jones,
Attorney-in-fact

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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).
2.4	Amendment No. 3 to the Purchase and Sale Agreement, dated as of August 29, 2007, 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 September 30, 2007).
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).

Exhibit	Description
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).
10.7	Federal Coal Lease dated as of June 24, 1993 between the U.S. 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).
10.8	Federal Coal Lease between the U.S. 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).
10.9	Federal Coal Lease dated as of July 19, 1997 between the U.S. 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).
10.10	Federal Coal Lease dated as of January 24, 1996 between the U.S. 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).
10.11	Federal Coal Lease Readjustment dated as of November 1, 1967 between the U.S. 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).
10.12	Federal Coal Lease effective as of May 1, 1995 between the U.S. 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).
10.13	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).
10.14	Federal Coal Lease dated as of October 1, 1999 between the U.S. 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).
10.15	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).
10.16	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).
10.17	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).
10.18	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 (incorporated by reference to Exhibit 10.20 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
10.19	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 (incorporated by reference to Exhibit 10.21 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
10.20	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 (incorporated by reference to Exhibit 10.22 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2006).

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Exhibit	Description
10.21	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).
10.22*	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).
10.23*	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).
10.24*	Arch Coal, Inc. 1997 Stock Incentive Plan (as Amended and Restated on July 22, 2004) (incorporated herein by reference to Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).
10.25*	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).
10.26*	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).
10.27*	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).
10.28	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).
10.29	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).
10.30	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).
10.31*	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).
10.32*	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).
10.33*	Form of Non-Qualified Stock Option Agreement (incorporated herein by reference to Exhibit 10.35 to the registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
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.