ARCH COAL INC
Form 10-K
February 27, 2009

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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, 2008

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 30, 2008 was approximately $10.8 billion.

On February 23, 2009, 142,862,991 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 23, 2009 are incorporated by reference into Part III of this Form 10-K.

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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 30. 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;
- competition within our industry and with producers of competing energy sources;
- excess production and production capacity;
- our ability to acquire or develop coal reserves in an economically feasible manner;
- inaccuracies in our estimates of our coal reserves;
- 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 collect payments from our customers;
- 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, a subsidiary of Patriot Coal Corporation, to satisfy certain below-market contracts that we guarantee;

our ability to manage the market and other risks associated with certain trading and other asset optimization strategies;

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, particulate matter or greenhouse gases;

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

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- 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, as well as other risks of which we are not aware or which we currently do not believe to be material, 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.

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PART I

ITEM 1. BUSINESS.

Introduction

We are one of the largest coal producers in the United States. For the year ended December 31, 2008, we sold approximately 139.6 million tons of coal, including approximately 6.1 million tons of coal we purchased from third parties, fueling approximately 6% of all electricity generated in the United States. We sell substantially all of our coal to power plants, steel mills and industrial facilities. At December 31, 2008, we operated 20 active mines located in each of the major low-sulfur coal-producing regions of the United States. The locations of our mines enable us to ship coal to most of the major coal-fueled power plants, steel mills and export facilities located in the United States.

Significant federal and state environmental regulations affect the demand for coal. Existing environmental regulations limiting the emission of certain impurities caused by coal combustion and new regulations, including those aimed at curbing the emission of certain greenhouse gases, have had and are likely to continue to have a considerable impact on our business. For example, certain federal and state environmental regulations currently limit the amount of sulfur dioxide that may be emitted as a result of combustion. As a result, we focus on mining, processing and marketing coal with low sulfur content.

Despite these and other regulations, we expect worldwide coal demand to increase over time, particularly in developing countries such as China and India where electricity demand is increasing much faster than in developed parts of the world. Although the global economic recession has had a significant impact in certain regions of the world, we expect worldwide energy demand to increase over the next 20 years. As a result of its availability, stability and affordability, we expect coal to satisfy a large portion of that demand.

Domestically, we anticipate that production in certain regions, particularly the Central Appalachian region, will decrease over time as reserves are depleted and permitting becomes more challenging. Although we expect coal exports to decline in 2009, we expect coal exports to increase gradually over the intermediate and longer term, as international consumers look for more stable sources of coal supplies. We also expect domestic coal consumption to increase over the intermediate and longer term. We believe that these trends collectively will exert upward pressure on coal pricing.

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, which we refer to as ARCO. 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 acquired a leasehold interest in 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 acquired a leasehold interest in 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.

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Coal Characteristics

In general, end users characterize coal of all geological compositions as steam coal or metallurgical coal. Heat value, sulfur and ash and moisture content, and volatility in the case of metallurgical coal, are the most important variables in the marketing and transportation of coal. These characteristics help producers determine the best end use of a particular type of coal. The following is a description of these general coal characteristics:

Heat Value. In general, the carbon content of coal supplies most of its heating value, but other factors also influence the amount of energy it contains per unit of weight. The heat value of coal is commonly measured in Btus. Coal is generally classified into four categories, ranging from lignite through subbituminous and bituminous to anthracite, reflecting the progressive response of individual deposits of coal to increasing heat and pressure. Anthracite is coal with the highest carbon content and, therefore, the highest heat value nearing 15,000 Btus per pound. Bituminous coal, used primarily to generate electricity and to make coke for the steel industry, has a heat value ranging between 10,500 and 15,500 Btus per pound. Subbituminous coal ranges from 8,300 to 13,000 Btus per pound and is generally used for electric power generation. Lignite coal is a geologically young coal which has the lowest carbon content and a heat value ranging between 4,000 and 8,300 Btus per pound.

Sulfur Content. Federal and state environmental regulations, including regulations that limit the amount of sulfur dioxide that may be emitted as a result of combustion, have affected and may continue to affect the demand for certain types of coal. The sulfur content of coal can vary from seam to seam and within a single seam. The chemical composition and concentration of sulfur in coal affects the amount of sulfur dioxide produced in combustion. Coal-fueled power plants can comply with sulfur dioxide emission regulations by burning coal with low sulfur content, blending coals with various sulfur contents, purchasing emission allowances on the open market and/or using sulfur-reduction technology.

All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 73.4% consist of compliance coal, while an additional 8.7% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Higher sulfur noncompliance coal can be burned in plants equipped with sulfur-reduction technology, such as scrubbers, and in facilities that blend compliance and noncompliance coal. We expect that all new coal-fueled power plants built in the United States will use some type of sulfur-reduction technology and, as such, the premiums offered for lower sulfur coal may decrease in the future.

Ash. Ash is the inorganic residue remaining after the combustion of coal. As with sulfur, ash content varies from seam to seam. Ash content is an important characteristic of coal because it impacts boiler performance and electric generating plants must handle and dispose of ash following combustion. The composition of the ash, including the proportion of sodium oxide, and fusion temperature are important characteristics of coal and help determine the suitability of the coal to end users. The absence of ash is also important to the process by which metallurgical coal is transformed into coke for use in steel production.

Moisture. Moisture content of coal varies by the type of coal, the region where it is mined and the location of the coal within a seam. In general, high moisture content decreases the heat value and increases the weight of the coal, thereby making it more expensive to transport. Moisture content in coal, on an as-sold basis, can range from approximately 2% to over 30% of the coal s weight.

Other. Users of metallurgical coal measure certain other characteristics, including fluidity, swelling capacity and volatility to assess the strength of coke produced from a given coal or the amount of coke that certain types of coal will yield. These characteristics may be important elements in determining the value of the metallurgical coal we produce and market.

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 41% of the world s electricity in 2006, according to the most recently available data from the International Energy Agency, which we refer to as the

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IEA. Coal is also used in producing approximately 64% of the world s steel supply. Coal reserves can be found in almost every country in the world, and recoverable coal can be found in approximately 70 countries.

Coal is traded worldwide and can be transported to demand centers by ship and by rail. Worldwide coal production approximated 7.2 billion tons in 2007 and 6.8 billion tons in 2006, according to the IEA. 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 World Coal Institute, which we refer to as the WCI. China, Indonesia and South Africa have also historically been significant exporters, however, growing energy demand in these areas has resulted in declining coal exports as many of these countries move toward greater self-sufficiency.

International demand for coal continues to be driven by rapid growth in electrical power generation capacity in Asia, particularly in China and India. China and India represented approximately 44% of total world coal consumption in 2005 and are expected to account for approximately 57% by 2030, according to the Energy Information Administration, which we refer to as the EIA. The increase in international demand has led to increased demand for coal exports from the United States. During 2008, coal exports for both steam and metallurgical coal increased significantly as demand for U.S. coal in the Atlantic Basin increased. This increase was a continuation of a trend that began in 2007 as demand for coal for both power generation and steel production exceeded global coal supplies. A weak U.S. dollar relative to foreign currencies, high freight rates and supply problems in Australia, South Africa and Indonesia, when combined, improved the competitiveness of U.S. coal in several international markets. During the second half of 2008, as the United States and most international economies deteriorated, demand for steam and metallurgical coal declined. We believe these economic challenges will continue to affect international demand in 2009 and, as a result, we expect U.S. coal exports to decline from record 2008 levels. Once global economic conditions improve, we expect U.S. exports to rebound.

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 increased from 398.1 million tons in 1960 to approximately 1.1 billion tons in 2008, based on preliminary information provided by the EIA. According to the EIA, approximately 98% of coal consumed in the United States in 2008 was from domestic production sources. The following chart shows historical and projected demand trends for U.S. coal by consuming sector for the periods indicated, according to the EIA:

	Actual		Forecast			Annual Growth		
Sector	**2001**	**2007**	**2010**	**2020**	**2030**	**2001-2010**	**2010-2020**	**2020-2030**
	(Tons, in millions)							
Electric power	964	1,046	1,056	1,110	1,210	0.9%	0.5%	0.9%
Other industrial	65	56	60	56	57	(0.8)%	(0.7)%	0.2%
Coke plants	26	23	21	19	18	(2.1)%	(1.0)%	(0.5)%
Residential/commercial	4	3	3	3	3	0.0%	0.0%	0.0%
Coal-to-liquids				30	70	n/a	n/a	8.8%
Total U.S. coal consumption	1,060	1,129	1,140	1,218	1,358	0.7%	0.7%	1.1%

Source: EIA Annual Energy Outlook 2009

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 48% of U.S. electricity generation in 2008 and is projected to grow by more than 20%, reaching 1.4 billion tons in 2030.

Coal is generally the lowest cost fossil-fuel used for baseload electric power generation and, historically, has been considerably less expensive than natural gas or oil. We estimate that the cost of generating electricity from

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coal is less than one-third of the cost of generating electricity from other fossil fuels. According to the EIA, the average delivered cost of coal to electric power generators during the first ten months of 2008 was $2.05/mm Btus, which was $14.88/mm Btus less expensive than petroleum liquids and $7.53/mm Btus less expensive than natural gas. Coal is also competitive with nuclear power generation, especially on a total cost per megawatt-hour basis. The production of electricity from existing hydroelectric facilities is inexpensive, but new sources are scarce and its application is limited by geography and susceptibility to seasonal and climatic conditions. In 2008, non-hydropower renewable power generation, such as wind power, accounted for only 3% of all electricity generated in the United States and is currently not economically competitive with existing technologies. The following chart sets forth the breakdown of U.S. electricity generation by energy source for 2007, according to the EIA:

Source: EIA Electric Power Annual (Jan. 21, 2009).

Coal consumption patterns are also influenced by the demand for electricity, governmental regulations affecting power generation, technological developments and the location, availability and cost of other energy sources such as nuclear and hydroelectric power. 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 almost 24% by 2030, despite projected efforts throughout the United States for industrial, residential and other consumers 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, which are the minimum amounts of electric power delivered or required over a given period of time at a steady rate. Based on estimates compiled by the EIA, U.S. coal consumption for electric generation is expected to grow approximately 1.5% per year until 2030. These amounts assume no future federal or state carbon emissions legislation is enacted and do not take into account recent market conditions.

Based on EIA projections, current capacity for electric generation may not be enough to support projected electricity demand. The EIA has projected that approximately 223 gigawatts of new electricity capacity will be needed between 2008 and 2030, with approximately 19% of the new capacity estimated to come from coal-fired generation. Planned new domestic coal-fueled electricity generation capacity announcements approximated 38 gigawatts at December 31, 2008, equating to more than 120 million tons of additional annual coal demand, based on information obtained from the National Energy Technology Laboratory and our internal estimates. We estimate that, at December 31, 2008, approximately 21 gigawatts of generating capacity was under construction or in advanced stages of development in the United States. Because the EIA projections are based on factors and assumptions contained in its forecasts, actual amounts of new capacity may differ significantly from those estimates and if they differ negatively, the amount of new electricity capacity needed may not grow as the EIA projects.

The proposed plants or expansions are utilizing the full spectrum of technologies from pulverized coal and circulating fluidized bed, which permit coal to be more easily burned, and integrated coal gasification cycle units, which permit coal to be turned into a gasified product for the easier capture of carbon in the future. Many projects that are moving forward are being developed by municipal and regulated utilities due to their ability to recover costs and prior experience with coal.

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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 reached record levels during 2008 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 proposed, including a coal-to-liquids facility 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 and energy security. 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 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 200 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 nearly 200 years. Annual coal production in the United States has increased from 434 million tons in 1960 to approximately 1.2 billion tons in 2008 based on information provided by EIA.

Coal is mined from coal fields through the United States, with the major production centers located in the western U.S., the Appalachian region and the Illinois Basin. The quality of coal varies by region. Heat value, sulfur content and suitability for production of metallurgical coke are important quality characteristics and are used to determine the best end use for the particular coal types.

The western region includes, among other areas, the Powder River Basin and the Western Bituminous region. According to the EIA, coal produced in the western United States increased from 408.3 million tons in 1994 to 635.9 million tons in 2008 as competitive mining costs and regulations limiting sulfur dioxide emissions have increased demand for low-sulfur coal over this period. The Powder River Basin is located in northeastern Wyoming and southeastern Montana. Coal from this region is sub-bituminous coal with low sulfur content ranging from 0.2% to 0.9% and heating values ranging from 8,000 to 9,500 Btu. 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 low sulfur content ranging from 0.4% to 0.8% and heating values ranging from 10,000 to 12,200 Btu.

The Appalachian region is divided into the north, central and southern Appalachian regions. According to the EIA, coal produced in the Appalachian region decreased from 445.4 million tons in 1994 to 389.6 million tons in 2008, primarily as a result of the depletion of economically attractive reserves, permitting issues and increasing costs of production. Central Appalachia includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. Coal mined from this region generally has a high heat value ranging from 11,400 to 13,200 Btu and a low sulfur content ranging from 0.2% to 2.0%. Northern Appalachia includes Maryland, Ohio, Pennsylvania and northern West Virginia. Coal from this region generally has a high heat value ranging from 10,300 to 13,500 Btu and a high sulfur content ranging from 0.8% to 4.0%.

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The Illinois basin includes Illinois, Indiana and western Kentucky and is the major coal production center in the interior region of the United States. According to the EIA, coal produced in the interior region decreased from 179.9 million tons in 1994 to 97.5 million tons in 2008. Coal from the Illinois basin generally has a heat value ranging from 10,100 to 12,600 Btu and has a high sulfur content ranging from 1.0% to 4.3%. 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.

U.S. Coal Exports and Imports. Coal exports increased from 71.4 million tons in 1994 to 82.6 million tons in 2008. As discussed above, as global coal consumption 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. We expect this development to continue over the long-term. However, we anticipate U.S. coal exports to decline in 2009 from 2008 levels because of the near-term global economic recession, record low freight rates and a stronger U.S. dollar relative to foreign currencies. We believe that the United States will continue to be a swing supplier of coal to the global marketplace in the near term.

Historically, coal imported from abroad has represented a relatively small share of total U.S. coal consumption. According to the EIA, coal imports increased from 8.9 million tons in 1994 to approximately 34.0 million tons in 2008. 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 do not expect coal imports into the United States to grow significantly 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 11. In 2008, approximately 79.0% of the coal that we produced came from surface mining operations.

Surface mining involves removing the topsoil and drilling or blasting the overburden (earth and rock covering the coal) with explosives. We then remove the overburden 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 plant life into the natural habitat 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 11. In 2008, approximately 21.0% 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. 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 2008, approximately 17.3% 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. 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. We currently conduct retreat mining in certain underground mines at our Cumberland River and Lone Mountain mining complexes. In 2008, the quantities of coal we recovered from retreat mining represented an insignificant portion of our total coal production. Once we finish mining in an area, we generally abandon that area and seal it from the rest of the mine. In 2008, approximately 3.3% of the coal that we produced came from underground mining operations generally using room-and-pillar mining techniques.

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

Coal Preparation and Blending. We generally crush the coal mined from our Powder River Basin mining complexes and ship it directly from our mines to the customer. Typically, no additional preparation is required for a saleable product. Coal extracted from some of our underground mining operations, particularly those mining thinner seams in Central Appalachia, 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 2008, our preparation plants processed approximately 83.9% of the raw coal we produced in the Central Appalachia region. In addition, depending on coal quality and customer requirements, we may blend coal mined from different locations, including coal produced by third parties, in order to achieve a more suitable product.

The treatments we employ at our preparation plants depend on the size of the raw coal. For course material, the separation process relies on the difference in the density between coal and waste rock where, for the very fine fractions, the separation process relies on the difference in surface chemical properties between coal and the waste minerals. 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 a pre-determined 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 process most coal sizes through centrifuges. A centrifuge spins coal very quickly, causing water accompanying the coal to separate.

For more information about the locations of our preparation plants, you should see the section entitled Our Mining Operations below.

Our Mining Operations

General. At December 31, 2008, we operated 20 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. We incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2008, 2007 and 2006 contained in Note 22 Segment Information to our consolidated financial statements beginning on page F-1.

Our operations in the Powder River Basin are located in Wyoming and include two surface mining complexes (Black Thunder and Coal Creek). Our operations in the Western Bituminous region are located in southern Wyoming, Colorado and Utah and include four underground mining complexes (Dugout Canyon, Skyline, Sufco and West Elk) and one surface mining complex (Arch of Wyoming) that includes one active surface mine and four inactive mines. Our operations in the Central Appalachia region are located in southern West Virginia, eastern Kentucky and southwestern Virginia and include four mining complexes (Coal-Mac, Cumberland River, Lone Mountain and Mountain Laurel) comprised of nine underground mines and four surface mines.

In general, we have developed our mining complexes at strategic locations in close proximity to our preparation plants and rail or barge shipping facilities. Coal is transported from our mining complexes to customers by means of railroads, trucks, barge lines, and ocean-going vessels from terminal facilities. We currently own or lease under long-term arrangements a substantial portion of the equipment utilized in our mining operations. We employ sophisticated preventative maintenance and rebuild programs and upgrade our equipment to ensure that it is productive, well-maintained and cost-competitive. Our maintenance programs also employ procedures designed to enhance the efficiencies 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 active mining complexes at December 31, 2008, the total sales associated with these complexes for the years ended December 31, 2006, 2007 and 2008 and the total reserves associated with these complexes at December 31, 2008. 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. The information included below the following table describes in more detail our mining operations, the coal mining methods used, certain characteristics of our coal and the method by which we transport coal from our mining operations to our customers or other third parties.

Mining Complex	**Captive Mines(1)**	**Contract Mines(1)**	**Mining Equipment**	**Railroad**	**Tons Sold(2) 2006**	**2007**	**2008**	**Total Cost of Property, Plant and Equipment at December 31, 2008 ($ in millions)**	**Assigned Reserves (Million tons)**
					(Million tons)				
Powder River Basin:									
Black Thunder	S		D, S	UP/BN	92.5	86.2	88.5	$ 751.2	1,250.7
Coal Creek(3)	S		D, S	UP/BN	3.1	10.2	11.5	148.2	206.1
Western Bituminous:									
Arch of Wyoming(4)	S		L, HW	UP			0.2	24.0	19.4
Dugout Canyon	U		LW, CM	UP	4.2	4.0	4.3	131.4	24.7
Skyline(3)	U		LW, CM	UP	1.5	2.4	3.3	189.3	19.9
Sufco	U		LW, CM	UP	7.4	6.7	7.4	213.2	44.9
West Elk	U		LW, CM	UP	5.0	6.2	5.3	390.5	70.9
Central Appalachia:									
Coal-Mac	S	U	L, E	NS/CSX	3.7	3.9	3.7	164.3	27.8
Cumberland River	S(2), U(3)	U	L, CM, HW	NS	2.6	2.4	2.4	126.3	23.3
Lone Mountain	U(3)		CM	NS/CSX	2.5	2.4	2.7	182.3	34.1
Mountain Laurel	U	S	L, LW, CM	CSX		1.0	4.3	428.4	90.7
Totals					122.5	125.4	133.6	$ 2,749.1	1,812.5

S = Surface mine
U = Underground mine

D = Dragline
L = Loader/truck

S = Shovel/truck
E = Excavator/truck
LW = Longwall
CM = 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, 2008. 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 and 1.7 million tons in 2006. The amount of coal that we purchased from third parties and processed through our loadout facilities was negligible in 2008. 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 6.0 million tons in 2008, 8.4 million tons in 2007 and 8.5 million tons in 2006.

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 that complex. That complex sold 1.2 million tons in 2007 and 4.0 million tons in 2006.

(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) We have four inactive mines at our Arch of Wyoming complex that are in the final process of reclamation and bond release.

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Powder River Basin

Black Thunder	Black Thunder is a surface mining complex located on approximately 24,300 acres in Campbell County, Wyoming. The Black Thunder mining complex extracts steam coal from the Upper Wyodak and Main Wyodak seams. The Black Thunder mining complex shipped 88.5 million tons of coal in 2008. We control a significant portion of the coal reserves through federal and state leases. The Black Thunder mining complex had approximately 1.3 billion tons of proven and probable reserves at December 31, 2008. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of 135.0 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021 before annual output starts to significantly decline, although in practice production would drop in phases extending the ultimate mine life. Several large tracts of coal adjacent to the Black Thunder mining complex have been nominated for lease, and other potential large areas of unleased coal remain available for nomination by us or other mining operations. The U.S. Department of Interior Bureau of Land Management, which we refer to as the BLM, will determine if the tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts. The Black Thunder mining complex currently consists of five active pit areas and two owned loadout facilities. 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 two hours.
Coal Creek	Coal Creek is a surface mining complex located on approximately 7,400 acres in Campbell County, Wyoming. The Coal Creek mining complex extracts steam coal from the Wyodak-R1 and Wyodak-R3 seams. The Coal Creek mining complex shipped 11.5 million tons of coal in 2008. We control a significant portion of the coal reserves through federal and state leases. The Coal Creek mining complex had approximately 206.1 million tons of proven and probable reserves at December 31, 2008. The air quality permit for the Coal Creek mine allows for the mining of coal at a rate of 50.0 million tons per year. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2025 before annual output starts to significantly decline. One large tract of coal adjacent to the Coal Creek mining complex has been nominated for lease, and other potential large areas of unleased coal remain available for nomination by us or other mining operations. The BLM will determine if these tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts.

The Coal Creek 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.

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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

Arch of Wyoming

Arch of Wyoming is a surface mining complex located in Carbon County, Wyoming. The Arch of Wyoming complex currently consists of one active surface mine and four inactive mines located on approximately 58,000 acres that are in the final process of reclamation and bond release. The Arch of Wyoming mining complex extracts coal from the Johnson seam. The Arch of Wyoming complex shipped 0.2 million tons of coal in 2008.

We control a significant portion of the coal reserves associated with this complex through federal, state and private leases. The active Arch of Wyoming mining operations had approximately 19.4 million tons of proven and probable reserves at December 31, 2008. The air quality permit for the active Arch of Wyoming mining operation allows for the mining of coal at a rate of 2.5 million tons per year. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2018 before annual output starts to significantly decline.

The active Arch of Wyoming mining operations currently consist of one active pit area. We ship all of the coal raw to our customers via the Union Pacific railroad and by truck. We do not process the coal mined at this complex.

Dugout Canyon

Dugout Canyon mine is an underground mining complex located on approximately 18,200 acres in Carbon County, Utah. The Dugout Canyon mining complex extracts steam coal from the Rock Canyon and Gilson seams. The Dugout Canyon mining complex shipped 4.3 million tons of coal in 2008.

We control a significant portion of the coal reserves through federal and state leases. The Dugout Canyon mining complex had approximately 24.7 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2013 before annual output starts to significantly decline.

The complex currently consists of a longwall, three 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. The Skyline mining complex extracts steam coal from the Lower O Conner A seam. The Skyline mining complex shipped 3.3 million tons of coal in 2008.

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	We control a significant portion of the coal reserves through federal leases and smaller portions through county and private leases. The Skyline mining complex had approximately 19.9 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2011 before annual output starts to significantly decline. The Skyline complex currently consists of a longwall, a continuous miner section and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad or by highway trucks. We process a portion of the coal mined at this complex at a nearby preparation plant. 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. The Sufco mining complex extracts steam coal from the Upper Hiawatha and Lower Hiawatha seams. The Sufco mining complex shipped 7.4 million tons of coal in 2008. We control a significant portion of the coal reserves through federal and state leases. The Sufco mining complex had approximately 44.9 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2014 before annual output starts to significantly decline. The Sufco 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. The West Elk mining complex extracts steam coal from the E seam. In the fourth quarter of 2008, we transitioned our longwall mining operation from the B seam to the E seam. The West Elk mining complex shipped 5.3 million tons of coal in 2008. We control a significant portion of the coal reserves through federal and state leases. The West Elk mining complex had approximately 70.9 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2019 before annual output starts to significantly decline. The West Elk complex currently consists of a longwall, three continuous miner sections and a loadout facility. We ship most of the coal raw to our

customers via the Union Pacific railroad. We process a portion of the coal mined at this complex at a nearby preparation plant. The loadout facility can load an 11,000-ton train in less than three hours.

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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. Surface mining operations at the Coal-Mac mining complex extract steam coal from the Coalburg and Stockton seams. Underground mining operations at the Coal-Mac mining complex extract steam coal from the Coalburg seam. The Coal-Mac mining complex shipped 3.7 million tons of coal in 2008. We control a significant portion of the coal reserves through private leases. The Coal-Mac mining complex had approximately 27.8 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2016 before annual output starts to significantly decline. The complex currently consists of one captive surface mine, 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 12,000-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 10,000-ton train in less than four hours.
Cumberland River	Cumberland River is an underground and surface mining complex located on approximately 17,000 acres in Wise County, Virginia and Letcher County, Kentucky. Surface mining operations at the Cumberland River mining complex extract steam coal from approximately 20 different coal seams from the Imboden seam to the High Splint No. 14 seam. Underground mining operations at the Cumberland River mining complex extract steam and metallurgical coal from the Imboden, Taggart Marker, Middle Taggart, Upper Taggart, Owl, and Parsons seams. The Cumberland River mining complex shipped 2.4 million tons of coal in 2008. We control a significant portion of the coal reserves through private leases. The Cumberland River mining complex had approximately 23.3 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2017 before annual output starts to significantly decline. The complex currently consists of four underground mines (three captive, one contract) operating 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. 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 is an underground mining complex located on approximately 22,000 acres in Harlan County, Kentucky and Lee County, Virginia. The Lone Mountain mining complex extracts steam and metallurgical coal from the Kellioka, Darby and Owl seams. The Lone Mountain mining complex shipped 2.7 million tons of coal in 2008.

We control a significant portion of the coal reserves through private leases. The Lone Mountain mining complex had approximately 34.1 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2017 before annual output starts to significantly decline.

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 and surface mining complex located on approximately 38,100 acres in Logan County, West Virginia. Underground mining operations at the Mountain Laurel mining complex extract steam and metallurgical coal from the Cedar Grove and Alma seams. Surface mining operations at the Mountain Laurel mining complex extract steam coal from a number of different splits of the Five Block, Stockton and Coalburg seams. The Mountain Laurel mining complex shipped 4.3 million tons of coal in 2008.

We control a significant portion of the coal reserves through private leases. The Mountain Laurel mining complex had approximately 90.7 million tons of proven and probable reserves at December 31, 2008. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2017 before annual output starts to significantly decline.

The complex currently consists of one underground mine operating a longwall and a total of four continuous miner sections, one contract surface operation, 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.

Sales, Marketing and Trading

Overview. Coal prices are influenced by a number of factors and vary materially 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, coal quality, transportation costs involved in moving coal from the mine to the point of use, mine operating costs and the costs and availability of alternative fuels, such as nuclear energy, natural gas, hydropower and

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petroleum. For example, higher carbon and lower ash content generally result in higher prices, and higher sulfur and higher ash content generally result in lower prices within a given geographic region.

The cost of coal at the mine is also 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.

Our sales, marketing and trading force is principally based in St. Louis, Missouri and consists of sales and trading personnel, transportation and distribution personnel, quality control personnel and contract administration personnel. In addition to selling coal produced in our mining complexes, from time to time, we purchase and sell coal mined by others, some of which we blend with coal produced from our mines. We focus on meeting the needs and specifications of our customers rather than just selling our coal production.

Customers. In 2008, we sold coal to domestic customers located in 35 different states. The majority of those customers operate power plants, steel mills and industrial facilities located throughout 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. For the year ended December 31, 2008, we derived approximately 24% of our total coal revenues from sales to our three largest customers, Tennessee Valley Authority, Ameren Corporation and TUCO, Inc., and approximately 48% of our total coal revenues from sales to our ten largest customers. During 2008, we also exported coal to customers located in 21 countries in North America, Europe, South America, Africa and Asia. Coal sales revenue from foreign customers approximated $486.1 million for 2008, $196.7 million for 2007 and $162.5 million for 2006. We seek to reduce our exposure to foreign currency fluctuations by settling all of our coal sales in U.S. dollars.

Worldwide steel prices increased significantly during the first half of 2008 due, in part, to shortages of raw materials, production control particularly in China in advance of the Beijing Olympics and spreading inflation in many parts of the globe. As the price of steel increased during the first six months of 2008, so too did the demand for metallurgical coal. We produced a higher percentage of metallurgical quality coal during 2008 than we did in 2007 or 2006 to take advantage of these favorable price trends. We sold approximately 4.4 million tons of metallurgical quality coal in 2008, approximately 2.1 million tons of metallurgical quality coal in 2007 and approximately 2.0 million tons of metallurgical quality coal in 2006.

Long-Term Coal Supply Arrangements

As is customary in the coal industry, we enter into fixed price, fixed volume long-term supply contracts, the terms of which are more than one year, with many of our customers. Multiple year contracts usually have specific and possibly different volume and pricing arrangements for each year of the contract. Long-term contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2008, we sold approximately 76% of our coal under long-term supply arrangements. Most of our supply contracts include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our long-term supply agreements may include a variable pricing system. While most of our sales contracts are for terms of one to five years, some are as short as one to 11 months and other contracts have terms longer than 10 years. At December 31, 2008, the average volume-weighted remaining term of our long-term contracts was approximately 3.4 years, with remaining terms ranging from one to nine years. At December 31, 2008, we had a sales backlog, including a backlog subject to price reopener or extension provisions, of approximately 311.7 million tons.

We typically sell coal to customers under long-term arrangements through a request-for-proposal process. The terms of our coal sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price reopener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, *force majeure*, termination and assignment provisions. Our long-term supply contracts generally contain provisions to adjust the base price due to new statutes, ordinances or regulations, such as the Mine Improvement and New Emergency Response Act of 2006, which we refer to as the MINER Act, that affect our costs related to performance of the agreement. Additionally, some of our contracts contain provisions that allow for the recovery of costs affected by modifications or changes in the interpretations or application of any applicable statute by local, state or federal government authorities. These provisions only apply to the base price of coal contained in these supply contracts. In some circumstances, a significant adjustment in base price can lead to termination of the contract.

Certain of our contracts contain price re-opener and index provisions that may allow a party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on prevailing market price or, in some instances, require us to negotiate a new price, sometimes between a specified range of prices. In a limited number of agreements, if the parties do not agree on a new price, either party has an option to terminate the contract. Under some of our contracts, we have the right to match lower prices offered to our customers by other suppliers. In addition, many of our contracts contain clauses which in some cases may allow customers to terminate the contract in the event of certain changes in environmental laws and regulations that impact their operations.

Quality and volumes for the coal are stipulated in coal sales agreements. In most cases, the annual pricing and volume obligations are fixed although in some cases the volume specified may vary depending on the quality of the coal. Most of our coal sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash and moisture content. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Our coal sales agreements also typically contain *force majeure* provisions allowing temporary suspension of performance by us, or our customers, during the duration of events beyond the control of the affected party, including events such as strikes, adverse mining conditions, mine closures or serious transportation problems that affect us or unanticipated plant outages that may affect the buyer. Our contracts generally provide that in the event a *force majeure* circumstance exceeds a certain time period the unaffected party may have the option to terminate the sale in whole or in part. Some contracts stipulate that this tonnage can be made up by mutual agreement or at the discretion of the buyer. Agreements between our customers and the railroads servicing our mines may also contain *force majeure* provisions. Generally, our coal sales agreements allow our customer to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a *force majeure*.

In most of our contracts, we have a right of substitution, allowing us to provide coal from different mines, including third-party mines, as long as the replacement coal meets quality specifications and will be sold at the same delivered cost.

Generally, under the terms of our coal supply contracts, we agree to indemnify or reimburse our customers for damage to their or their rail carrier s equipment while on our property, other than from their own negligence, and for damage to our customer s equipment due to non-coal materials being included with our coal before leaving our property.

Trading. In addition to marketing and selling coal to customers through traditional coal supply arrangements, we seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of other marketing, trading and asset optimization strategies. From time to time, we may employ strategies to use coal and coal-related commodities and contracts for those commodities in order to manage and hedge fixed price coal sales or purchase commitments, reduce our exposure to the volatility of market prices or augment the value of our portfolio of traditional assets. These strategies may include physical coal, as well as a variety of forward, futures or options contracts, swap agreements or other financial instruments.

We maintain a system of complementary processes and controls designed to monitor and manage our exposure to market and other risks that may arise as a consequence of these strategies. These processes and controls seek to preserve our ability to profit from certain marketing, trading and asset optimization strategies while mitigating our exposure to potential losses. You should see the section entitled Quantitative and Qualitative Disclosures About Market Risk beginning on page 67 for more information about the market risks associated with these strategies at December 31, 2008.

Transportation. We ship our coal to domestic customers by means of railroad, barges or trucks, or a combination of these means of transportation. We generally sell coal used for domestic consumption free on board at the mine or nearest loading facility. Our domestic customers normally bear the costs of transporting coal by rail or barge.

We generally sell coal to international customers at the export terminal, and we are usually responsible for the cost of transporting coal to the export terminals. We transport our coal to Atlantic or Pacific coast terminals or terminals along the Gulf of Mexico for transportation to international customers. Our international customers are generally responsible for paying the cost of ocean freight.

We own a 22% 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.

Historically, most domestic electricity generators have arranged long-term shipping contracts with rail or barge companies to assure stable delivery costs. Transportation can be a large component of a purchaser s total cost. Although the purchaser pays the freight, transportation costs still are important to coal mining companies because the purchaser may choose a supplier largely based on cost of transportation. Transportation costs borne by the customer vary greatly based on each customer s proximity to the mine and our proximity to the loadout facilities. Trucks and overland conveyors haul coal over shorter distances, while barges, Great Lake carriers and ocean vessels move coal to export markets and domestic markets requiring shipment over the Great Lakes and several river systems.

Most coal mines are served by a single rail company, but much of the Powder River Basin is served by two rail carriers: the Burlington Northern Santa Fe Railway and the Union Pacific Railroad. In the Western Bituminous region, our customers are largely served by the Union Pacific Railroad. We generally transport coal produced at our Central Appalachian mining complexes via the CSX Railway or the Norfolk Southern Railway. Besides rail deliveries, some customers in the eastern U.S. rely on a river barge system. 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 load up to six million tons of coal annually for shipment on the inland waterways.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality, delivered costs to the customer and the reliability of supply. Our principal domestic competitors include Alpha Natural Resources, Inc., CONSOL Energy Inc., Foundation Coal Holdings, Inc., 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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Suppliers

Principal supplies used in our business include petroleum-based fuels, explosives, tires, steel and other raw materials as well as spare parts and other consumables used in the mining process. We use third-party suppliers for a significant portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business such as dragline shovel parts and services and tires. We believe adequate substitute suppliers are available. For more information about our suppliers, you should see Risk Factors 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.

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety and the environment, including protection of air quality, water quality, wetlands, special status species of plants and animals, land uses, cultural and historic properties and other environmental resources identified during the permitting process. Contemporaneous reclamation is required during and after mining has been completed. Materials used and generated by mining operations must also be managed according to applicable regulations and law. These laws have, and will continue to have, a significant effect on our production costs and our competitive position. Future laws, regulations or orders, as well as future interpretations and more rigorous enforcement of existing laws, regulations or orders, may require substantial increases in equipment and operating costs and delays, interruptions or a termination of operations, the extent to which we cannot predict. Future laws, regulations or orders may also cause coal to become a less attractive fuel source, thereby reducing coal s share of the market for fuels and other energy sources used to generate electricity. As a result, future laws, regulations or orders may adversely affect our mining operations, cost structure or our customers demand for coal.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, due in part to the extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. We cannot assure you that we have been or will be at all times in complete compliance with such laws and regulations. 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:

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 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. For example, in order to obtain a federal coal lease, an environmental impact statement must be prepared to assist the BLM in determining the potential environmental impact of lease issuance, including any collateral effects from the mining, transportation and burning of coal. The authorization, permitting and implementation requirements imposed by federal, state and local authorities may be costly and time consuming and may delay commencement or continuation of mining operations. In the states where we operate, the applicable laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if officers, directors, shareholders with specified interests or certain other affiliated entities with specified interests in the applicant or permittee have, or are affiliated with another entity that has, outstanding permit violations. Thus, past or ongoing violations of applicable laws and regulations could provide a basis to revoke existing permits and to deny the issuance of additional permits.

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In order to obtain mining permits and approvals from federal and 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 or other authorized use. 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.

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 regulatory 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. All states in which we conduct mining operations have achieved primacy and issue permits in lieu of OSM.

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. We begin the process of preparing a mining permit application 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 and information derived from the other surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application. 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 OSM 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 2008, we recorded $37.1 million of expense related to these reclamation fees.

Surety Bonds. Mine operators are often required by federal and/or state laws, including SMCRA, 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 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, 2008, we have self-bonded an aggregate of $334.6 million and have posted an aggregate of $241.0 million in surety bonds for reclamation purposes. In addition, we had approximately $140.0 million of surety bonds and letters of credit outstanding at December 31, 2008 to secure workers compensation, coal lease and other obligations.

Mine Safety and Health. 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 aimed at improving mine safety and health. Collectively, federal and state safety and health regulation in the coal mining industry is among the most comprehensive and pervasive systems for the protection of employee health and safety affecting any segment of U.S. industry. In reaction to recent mine accidents, 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 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.

In 2008, the U.S. House of Representatives approved additional federal legislation which would have required new regulations on a variety of mine safety issues such as underground refuges, mine ventilation and communication systems. Although the U.S. Senate failed to pass that legislation, it is possible that similar legislation may be proposed in the future. Various states, including West Virginia, have also enacted new laws to address many of the same subjects. The costs of implementing these new safety and health regulations at the federal and state level have been, and will continue to be, substantial. In addition to the cost of implementation, there are increased penalties for violations which may also be substantial. Expanded enforcement has resulted 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 2008, we recorded $71.7 million of expense related to this excise tax.

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 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, promulgated in 1990, imposed 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 been factored into the pricing of the coal market.

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 12 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 new 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 then-current 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 still subject to judicial challenge, however, making its impact difficult to assess. Nonetheless, if the EPA s current rules are upheld and if the new, more stringent ozone NAAQS withstand scrutiny, 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

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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, which could make 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 28 eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide pursuant to 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. 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. In July 2008, in *State of North Carolina v. EPA* and consolidated cases, the U.S. Court of Appeals for the District of Columbia Circuit disagreed with the EPA s reading of the Clean Air Act and vacated CAIR in its entirety. In December 2008, the U.S. Court of Appeals for the District of Columbia Circuit revised its remedy and remanded the rule to the EPA. The result is that CAIR will be implemented and will remain in effect at least until the EPA responds to the remand. Accordingly, new emissions controls that have been constructed will be operated in 2009 in response to CAIR.

Mercury. In February 2008, the U.S. 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 from 48 tons to 38 tons a year 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.

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 operations 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.

New Source Review. A number of pending regulatory changes and court actions will affect the scope of the EPA s new source review program, which under certain circumstances requires existing coal-fueled power plants to install the more stringent air emissions control equipment required of new plants. The changes to the new source review program may impact demand for coal nationally, but as the final form of the requirements after their revision is not yet known, we are unable to predict the magnitude of the impact.

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.

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. The U.S. Congress has considered various proposals to reduce greenhouse gas emissions, but to date, none have become law. 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. Although *Massachusetts v. EPA* did not involve the EPA s authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the decision is likely to impact regulation of stationary sources. For example, a challenge in the U.S. Court of Appeals for the District of Columbia with respect to the EPA s decision not to regulate greenhouse gas emissions from power plants and other stationary sources under the Clean Air Act s new source performance standards was remanded to the EPA for further consideration in light of *Massachusetts v. EPA*. 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. In response to *Massachusetts v. EPA*, in July 2008, the EPA issued a notice of proposed rulemaking requesting public comment on the regulation of greenhouse gases. If as a result of these actions the EPA were to set emission limits for carbon dioxide from electric utilities or steel mills, the demand for coal could decrease.

In the absence of federal legislation or regulation, many states and regions have adopted greenhouse gas initiatives. In 2002, the Conference of New England Governors and Eastern Canadian Premiers adopted a Climate Change Action Plan, calling for reduction in regional greenhouse gas 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 implementation of a cap and trade program by 2009 aimed at reducing carbon dioxide emissions from power plants in the participating states. Since its inception, several additional northeastern states and Canadian provinces have joined as participants or observers. RGGI held its first carbon dioxide allowance auction in September 2008 and will hold quarterly auctions during the initial three-year compliance period from January 1, 2009 to December 31, 2011 to allow utilities to buy allowances to cover their carbon dioxide emissions.

Climate change initiatives are also being considered or enacted in some western states. In September 2006, California adopted the Global Warming Solutions Act of 2006, which establishes a statewide greenhouse gas emissions cap of 1990 levels by 2020 and sets a framework for further reductions after 2020. In September 2006, California also 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 to 15% below 2005 levels by 2020. Since its initial launching, a number of additional western states and Canadian provinces have joined the initiative or have agreed to participate as observers. The proposed scope of the cap and trade program pursuant to the Western Climate Initiative includes fossil fuels, such as coal, production and processing. As a result, our coal mines could incur direct costs if the proposals are implemented by Montana and Wyoming, although we currently do not believe that any such direct costs on our operations would be material.

Midwestern states have also adopted initiatives to reduce and monitor greenhouse gas emissions. 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 and regional 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 or at the federal level, will not affect the future market for coal in those regions. The permitting of new coal-fueled power plants has also recently been contested by state regulators and environmental organizations based on concerns relating to greenhouse gas emissions. Increased efforts to control greenhouse gas emissions could result in reduced demand for coal.

Clean Water Act. The federal Clean Water Act and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including dredged and fill materials, into waters of the United States. The Clean Water Act provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Recent court decisions and regulatory actions have created uncertainty over Clean Water Act jurisdiction and permitting requirements that could variously increase or decrease the cost and time we expend on Clean Water Act compliance.

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 discharges into waters of the United States. Discharges that exceed the limits specified under NPDES permits can lead to the imposition of penalties, and persistent non-compliance could lead to significant penalties, compliance costs and delays in coal production. In addition, the imposition of future restrictions on the discharge of certain pollutants into waters of the United States could increase the difficulty of obtaining and complying with NPDES permits, which could impose additional time and cost burdens on our operations. You should see Item 3 Legal Proceedings beginning on page 45 for more information about certain regulatory actions pertaining to our operations.

Discharges of pollutants into waters that states have designated as impaired (i.e., as not meeting present water quality standards) are subject to Total Maximum Daily Load, which we refer to as TMDL, regulations. The TMDL regulations establish a process for calculating the maximum amount of a pollutant that a water body can receive while maintaining state water quality standards. Pollutant loads are allocated among the various sources that discharge pollutants into that water body. Mine operations that discharge into water bodies designated as impaired will be required to meet new TMDL allocations. The adoption of more stringent TMDL-related allocations for our coal mines could require more costly water treatment and could adversely affect our coal production.

The Clean Water Act also requires states to develop anti-degradation policies to ensure that non-impaired water bodies continue to meet water quality standards. The issuance and renewal of permits for the discharge of pollutants to waters that have been designated as high quality are subject to anti-degradation review that may increase the costs, time and difficulty associated with obtaining and complying with NPDES permits.

> *Dredge and Fill Permits.* 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. Under the Clean Water Act, coal companies are required to obtain a Section 404 permit from the Army Corps of Engineers, which we refer to as the Corps, prior to conducting such mining activities. The Corps is authorized to issue general nationwide permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse effects on the environment. Permits issued pursuant to Nationwide Permit 21, which we refer to as NWP 21, generally authorize the disposal of dredged and fill material from surface coal mining activities into waters of the United States, subject to certain restrictions. Since March 2007, permits under NWP 21 were reissued for a five-year period with new provisions intended to strengthen environmental protections. There must be appropriate mitigation in accordance with nationwide general permit conditions rather than less restricted state-required mitigation requirements, and permitholders must receive explicit authorization from the Corps before proceeding with proposed mining activities.

The use of nationwide permits to authorize stream impacts from mining activities has been the subject of significant litigation. You should see Item 3 Legal Proceedings beginning on page 45 for more information about certain litigation pertaining to our permits.

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.

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.

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

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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.

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. In addition, the storage of explosives is subject to strict regulatory requirements established by four different federal regulatory agencies. For example, pursuant to a rule issued by the Department of Homeland Security in 2007, facilities in possession of chemicals of interest, including ammonium nitrate at certain threshold levels, must complete a screening review in order to help determine whether there is a high level of security risk such that a security vulnerability assessment and site security plan will be required.

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.

Employees

General. At February 15, 2009, we employed a total of approximately 4,300 persons, approximately 240 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, 2009 and their positions and offices during the last five years:

Name	Age	Position
C. Henry Besten, Jr.	60	Mr. Besten has served as our Senior Vice President-Strategic Development since 2002.
John T. Drexler	39	Mr. Drexler has served as our Senior Vice President and Chief Financial Officer since April 2008. Mr. Drexler served as our Vice President-Finance and Accounting from March 2006 to April 2008. From March 2005 to March 2006, Mr. Drexler served as our Director of Planning and Forecasting. Prior to March 2005, Mr. Drexler held several other positions within our finance and accounting department.
John W. Eaves	51	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	54	Ms. Feldman has served as our Vice President-Human Resources since 2003. From 1997 to 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	52	Mr. Jones has served as our Senior Vice President-Law, General Counsel and Secretary since August 2008. Mr. Jones served as Vice President-Law, General Counsel and Secretary from 2000 to August 2008.
Paul A. Lang	48	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 1998 through July 2005.
Steven F. Leer	56	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 past 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.
David B. Peugh	54	Mr. Peugh has served as our Vice President-Business Development since 1995.
Deck S. Slone	45	Mr. Slone has served as our Vice President-Government, Investor and Public Affairs since August 2008. Mr. Slone served as our Vice

		President-Investor Relations and Public Affairs from 2001 to August 2008.
David N. Warnecke	53	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 27, 2008.

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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 without charge 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, 63141 Attention: Vice President-Government, Investor 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

Coal prices are subject to change and a substantial or extended decline in prices could materially and adversely 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. The contract prices we may receive in the future for coal depend upon factors beyond our control, including the following:

- the domestic and foreign supply and demand for coal;
- the quantity and quality of coal available from competitors;
- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels, such as natural gas and oil, and alternative energy sources, such as nuclear, hydroelectric, wind and solar power;
- domestic air emission standards for coal-fueled power plants and the ability of coal-fueled power plants to meet these standards by installing scrubbers or other means;
- adverse weather, climatic or other natural conditions, including natural disasters;
- domestic and foreign economic conditions, including economic slowdowns;
- legislative, regulatory and judicial developments, environmental regulatory changes or changes in energy policy and energy conservation measures that would adversely affect the coal industry, such as legislation limiting carbon emissions or providing for increased funding and incentives for alternative energy sources;
- the proximity, capacity and cost of transportation facilities; and

market price fluctuations for sulfur dioxide emission allowances.

A substantial or extended decline in the prices we receive for our future coal sales contracts could materially and adversely affect us by decreasing our profitability and the value of our coal reserves.

Our coal mining operations are subject to operating risks that are beyond our control, which could result in materially increased operating expenses and decreased production levels and could materially and adversely affect our profitability.

We mine coal at underground and surface mining operations. Certain factors beyond our control, including those listed below, could disrupt our coal mining operations, adversely affect production and shipments and increase our operating costs, all of which could have a material adverse effect on our results of operations:

- poor mining conditions resulting from geological, hydrologic or other conditions that may cause instability of highwalls or spoil piles or cause damage to nearby infrastructure or mine personnel;
- a major incident at the mine site that causes all or part of the operations of the mine to cease for some period of time;
- mining, processing and plant equipment failures and unexpected maintenance problems;
- adverse weather and natural disasters, such as heavy rains or snow, flooding and other natural events affecting operations, transportation or customers;
- unexpected or accidental surface subsidence from underground mining;
- accidental mine water discharges, fires, explosions or similar mining accidents; and
- competition and/or conflicts with other natural resource extraction activities and production within our operating areas, such as coalbed methane extraction or oil and gas development.

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 shipments 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.

Competition within our industry and with producers of competing energy sources may materially and adversely affect our ability to sell coal at favorable prices.

We compete with numerous other coal producers in various regions of the United States for domestic sales. International demand for U.S. coal also affects competition within our industry. The demand for U.S. coal exports depends upon a number of factors outside our control, including the overall demand for electricity in foreign markets, currency exchange rates, ocean freight rates, port and shipping capacity, the demand for foreign-priced steel, both in foreign markets and in the U.S. market, general economic conditions in foreign countries, technological developments and environmental and other governmental regulations. Foreign demand for Central Appalachian coal has increased in recent periods. If foreign demand for U.S. coal were to decline, this decline could cause competition among coal producers for the sale of coal in the United States to intensify, potentially resulting in significant downward pressure on domestic coal prices.

In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas and oil. In recent periods, prices for competing fuels have reached historically high levels. A decline in the price for these fuels could cause demand for coal to decrease and adversely affect the price of our coal. If alternative energy sources, such as wind or solar, become more cost-competitive on an overall basis, including capital expenditures and conversion, storage and transmission costs, demand for coal could decrease and the price of coal could be materially and adversely affected.

Excess production and production capacity in the coal industry could put downward pressure on coal prices and, as a result, materially and adversely affect our revenues and profitability.

During the mid-1970s and early 1980s, increased demand for coal attracted new investors to the coal industry, spurred the development of new mines and resulted in additional production capacity throughout the industry, all of which led to increased competition and lower coal prices. Increases in coal prices over the past several years have encouraged the development of expanded capacity by coal producers and may continue to do so. Any resulting overcapacity and increased production could materially reduce coal prices and therefore materially reduce our revenues and profitability.

Decreases in demand for electricity resulting from economic, weather changes or other conditions could adversely affect coal prices and materially and adversely affect our results of operations.

Our coal is primarily used as fuel for electricity generation. Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand. An economic slowdown can significantly slow the growth of electrical demand and could result in contraction of demand for coal. Declines in international prices for coal generally will impact U.S. prices for coal. During the past several years, international demand for coal has been driven, in significant part, by fluctuations in demand due to economic growth in China and India as well as other developing countries. Significant declines in the rates of economic growth in these regions could materially affect international demand for U.S. coal, which may have an adverse effect on U.S. coal prices.

Weather patterns can also greatly affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increased generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand, which allows generators to choose the sources of power generation when deciding which generation sources to dispatch. Any downward pressure on coal prices, due to decreases in overall demand or otherwise, including changes in weather patterns, would materially and adversely affect our results of operations.

The use of alternative energy sources for power generation could reduce coal consumption by U.S. electric power generators, which could result in lower prices for our coal. Declines in the prices at which we sell our coal could reduce our revenues and materially and adversely affect our business and results of operations.

In 2008, approximately 85.9% of the tons we sold were to domestic electric power generators. Domestic electric power generation accounted for approximately 92.7% of all U.S. coal consumption in 2007, according to the EIA. The amount of coal consumed for U.S. electric power generation is affected by, among other things:

- the location, availability, quality and price of alternative energy sources for power generation, such as natural gas, fuel oil, nuclear, hydroelectric, wind and solar power; and
- technological developments, including those related to alternative energy sources.

Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators. In addition, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reduction in the amount of coal consumed by domestic electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

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

Our profitability depends substantially on our ability to mine and process, in a cost-effective manner, coal reserves that possess the quality characteristics desired by our customers. As we mine, our coal reserves decline.

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As a result, our future success depends upon our ability to acquire additional coal that is economically recoverable. If we fail to acquire or develop additional coal reserves, our existing reserves will eventually be depleted. 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 the availability of cash we generate from our operations or available financing, restrictions under our existing or future financing arrangements, and competition from other coal producers, the lack of suitable acquisition or lease-by-application, or LBA, opportunities or the inability to acquire coal properties or LBAs on commercially reasonable terms. If we are unable to acquire replacement reserves, our future production may decrease significantly and our operating results may be negatively affected. In addition, we may not be able to mine future reserves as profitably as we do at our current operations.

Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs.

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. We base our estimates of reserves on engineering, economic and geological data assembled, analyzed and reviewed by internal and third-party engineers and consultants. We update our estimates of the quantity and quality of proven and probable coal reserves annually to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;
- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;
- the percentage of coal ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- assumptions concerning the timing for the development of the reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy in our estimates related to our reserves could result in decreased profitability from lower than expected revenues and/or higher than expected costs.

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, explosives, 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. In the past several years, we have experienced shortages of certain large rubber tires we use in our mining operations. We have mitigated these shortages by purchasing less efficient large rubber tires at higher costs. In addition, 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. In the future, we may be unable to obtain a sufficient quantity of rubber tires 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 in multiple disciplines such as electricians, equipment operators, engineers and welders, among others. 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 ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

We have contracts to supply coal to energy trading and brokering companies under which they purchase the coal for their own account or resell the coal to end users. Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If we determine that a customer is not creditworthy, we may not be required to deliver coal under the customer s coal sales contract. If this occurs, we may decide to sell the customer s coal on the spot market, which may be at prices lower than the contracted price, or we may be unable to sell the coal at all. Furthermore, the bankruptcy of any of our customers could materially and adversely affect our financial position. In addition, our customer base may change with deregulation as utilities sell their power plants to their non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear for customer payment default. These new power plant owners may have credit ratings that are below investment grade, or may become below investment grade after we enter into contracts with them. In addition, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk of payment default.

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 17.

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

For the year ended December 31, 2008, we derived approximately 24% of our total coal revenues from sales to our three largest customers and approximately 48% of our total coal revenues from sales to our ten largest customers. We expect to renew, extend or enter into new long-term coal supply agreements with those and other customers. However, we may be unsuccessful in obtaining long-term coal supply agreements with those customers, and those customers may discontinue purchasing coal from us. If any of those customers, particularly any of our three largest customers, was to significantly reduce the quantities of coal it purchases from us, or if we are unable to sell coal to those customers on terms as favorable to us as the terms under our current long-term coal supply agreements, our profitability could suffer significantly. We have limited protection during adverse economic conditions and may face economic penalties if we are unable to satisfy certain quality specifications under our long-term coal supply agreements.

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

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

At December 31, 2008, 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 have significant consequences to us, such as:

- limiting our ability to obtain additional financing to fund growth, such as new LBA acquisitions or other mergers and acquisitions, working capital, capital expenditures, debt service requirements or other cash requirements
- exposing us to the risk of increased interest costs if the underlying interest rates rise;
- limiting our ability to invest operating cash flow in our business due to existing debt service requirements;
- making it more difficult to obtain surety bonds, letters of credit or other financing, particularly during weak credit markets;

causing a decline in our credit ratings;

limiting our ability to compete with companies that are not as leveraged and that may be better positioned to withstand economic downturns;

limiting our ability to acquire new coal reserves and/or plant and equipment needed to conduct operations; and

limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we compete and general economic and market conditions.

If we further increase our indebtedness, the related risks that we now face, including those described above, could intensify. In addition to the principal repayments on our outstanding debt, we have other demands on our cash resources, including capital expenditures and operating expenses. Our ability to pay our debt depends upon our operating performance. In particular, economic conditions could cause our revenues to decline, and hamper our ability to repay our indebtedness. If we do not have enough cash to satisfy our debt service obligations, we may be required to refinance all or part of our debt, sell assets or reduce our spending. We may not be able to, at any given time, refinance our debt or sell assets on terms acceptable to us or at all.

Volatility and disruptions in the capital and credit markets could adversely affect our business, including affecting the cost of new capital, our ability to refinance scheduled debt maturities and meet other obligations as they come due.

Capital and credit markets can experience extreme volatility and disruption. This volatility and disruption can exert extreme downward pressure on stock prices and upward pressure on the cost of new debt capital and can severely restrict credit availability. These disruptions can also result in higher interest rates on publicly issued debt securities and increased costs under credit facilities. These disruptions could increase our interest expense and adversely affect our results of operations and financial position.

Our access to funds under our financing arrangements is dependent on the ability of the financial institutions that are parties to those arrangements to meet their funding commitments. Those financial institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time.

Longer term volatility and continued disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation of financial institutions, reduced alternatives or failures of significant financial institutions could adversely affect our access to the liquidity needed for our business in the longer term. Such disruptions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged.

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

The agreements governing our outstanding financing arrangements 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. 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. As a result, a default under one or more of our existing or future financing arrangements could have significant consequences 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 58.

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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 may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required by state and federal law to have these bonds in place before mining can commence or continue, or failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third party surety bond issuers of their right to refuse to renew the surety and restrictions on availability on collateral for current and future third party surety bond issuers under the terms of our financing arrangements.

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, 2008, if we had purchased the 17.8 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 $305.4 million.

We may incur losses as a result of certain marketing, trading and asset optimization strategies.

We seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of marketing, trading and other asset optimization strategies. We maintain a system of complementary processes and controls designed to monitor and control our exposure to market and other risks as a consequence of these strategies. These processes and controls seek to balance our ability to profit from certain marketing, trading and asset optimization strategies with our exposure to potential losses. While we employ a variety of risk monitoring and mitigation techniques, those techniques and accompanying judgments cannot anticipate every potential outcome or the timing of such outcomes. In addition, the processes and controls that we use to manage our exposure to market and other risks resulting from these strategies involve assumptions about the degrees of correlation or lack thereof among prices of various assets or other market indicators. These correlations may change significantly in times of market turbulence or other unforeseen circumstances. As a result, we may experience volatility in our earnings as a result of our marketing, trading and asset optimization strategies.

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

Extensive environmental regulations, including existing and potential future regulatory requirements relating to air emissions, affect our customers and could reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline.

The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, the federal Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, sulfur dioxide, nitrogen oxide and other air pollutants are expected to be proposed or become effective in coming years. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

Considerable uncertainty is associated with these air emissions initiatives. The content of regulatory requirements in the U.S. is in the process of being developed, and many new regulatory initiatives remain subject to review by federal or state agencies or the courts. Stringent air emissions limitations are either in place or are likely to be imposed in the short to medium term, and these limitations will likely require significant emissions control expenditures for many coal-fueled power plants. As a result, these power plants may switch to other fuels that generate fewer of these emissions or may install more effective pollution control equipment that reduces the need for low sulfur coal, possibly reducing future demand for coal and a reduced need to construct new coal-fueled power plants. The EIA s expectations for the coal industry assume there will be a significant number of as yet unplanned coal-fired plants built in the future which may not occur. Any switching of fuel sources away from coal, closure of existing coal-fired plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal. Alternatively, less stringent air emissions limitations, particularly related to sulfur, to the extent enacted could make low sulfur coal less attractive, which could also have a material adverse effect on the demand for and prices received for our coal.

You should see Environmental and Other Regulatory Matters beginning on page 20 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 impose strict regulations on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. The permitting rules, and the interpretations of these rules, are complex, change frequently and are often subject to discretionary interpretations by the regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing operations or the development of future mining operations. The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, and otherwise engage in the permitting process, including bringing citizens lawsuits to challenge the issuance of permits, the validity of environmental impact statements or performance of mining activities. Accordingly, required permits may not be issued or renewed in a timely fashion or at all, or permits issued or renewed may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow and profitability.

Federal or state regulatory agencies have the authority to order certain of our mines to be temporarily or permanently closed under certain circumstances, which could materially and adversely affect our ability to meet

our customers demands.

Federal or state regulatory agencies have the authority under certain circumstances following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this occurred, we may be required to incur capital expenditures to re-open the mine. In the event that these agencies

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order the closing of our mines, our coal sales contracts generally permit us to issue *force majeure* notices which suspend our obligations to deliver coal under these contracts. However, our customers may challenge our issuances of *force majeure* notices. If these challenges are successful, we may have to purchase coal from third-party sources, if it is available, to fulfill these obligations, incur capital expenditures to re-open the mines and/or negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery or terminate customers contracts. Any of these actions could have a material adverse effect on our business and results of operations.

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 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.

Extensive environmental regulations impose significant costs on our mining operations, and future regulations could materially increase those costs or limit our ability to produce and sell coal.

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

- limitations on land use;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management of materials generated by mining operations;
- the storage, treatment and disposal of wastes;

remediation of contaminated soil and groundwater;

air quality standards;

water pollution;

protection of human health, plant-life and wildlife, including endangered or threatened species;

protection of wetlands;

the discharge of materials into the environment;

the effects of mining on surface water and groundwater quality and availability; and

the management of electrical equipment containing polychlorinated biphenyls.

The costs, liabilities and requirements associated with the laws and regulations related to these and other environmental matters may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. We cannot assure you that we have been or will be at all times in compliance with the applicable laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may incur material costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. If we are pursued for sanctions, costs and liabilities in respect of these matters, our mining operations and, as a result, our profitability could be materially and adversely affected.

New legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations, including proposals related to the protection of the environment that would further regulate and tax the coal industry, may also require us to change operations significantly or incur increased costs. Such changes could have a material adverse effect on our financial condition and results of operations. You should see Environmental and Other Regulatory Matters beginning on page 20 for more information about the various governmental regulations affecting us.

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

SMCRA and counterpart state laws and regulations establish 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, engineering studies 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 our original 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. The resulting estimated reclamation and mine closure obligations could change significantly if actual amounts change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial condition.

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. Two of our operating subsidiaries intervened in the suit to protect their interests in being allowed to operate under the issued permits, and one of them thereafter was dismissed. On February 13, 2009, the U.S. Court of Appeals for the Fourth Circuit ruled on appeals from decisions rendered prior to our intervention, which may have a favorable impact on our permits. The decision of the Fourth Circuit remains subject to appeal. 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 45 for more information about the litigation described above.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our Properties

General

At December 31, 2008, we owned or controlled primarily through long-term leases approximately 99,700 acres of coal land in West Virginia, 98,300 acres of coal land in Wyoming, 98,700 acres of coal land in Illinois, 69,800 acres of coal land in Utah, 48,200 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 36,000 acres of our coal land from various state governments. 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 Our Mining Operations beginning on page 10 for more information about our mining operations, mining complexes and transportation facilities.

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Our Coal Reserves

We estimate that we owned or controlled approximately 2.8 billion tons of proven and probable recoverable reserves at December 31, 2008. Our coal reserve estimates at December 31, 2008 were prepared by our engineers and geologists and reviewed by Weir International, Inc., a mining and geological consultant. Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data. Our coal reserve estimates are periodically updated to reflect past coal production and other geologic and mining data. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam.

Our coal reserve estimates include reserves that can be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, our potential inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtaining mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. We use various assumptions in preparing our estimates of our coal reserves. You should see   Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs   contained under the heading   Risk Factors   beginning on page 30 for more information.

The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2008:

Total Assigned Reserves

(Tons in millions)

	Total Assigned 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	Past Reserve Estimates 2006	2007
yoming	1,476	1,440	36	1,429	47		8,849	1,461	15	1,476		1,655	1,54
ah	89	54	35	82	7		11,441	88	1		89	110	10
lorado	71	55	16	71			11,703	71			71	67	7
ntral App	176	167	9	59	117		12,791	169	7	77	99	216	16
nois													
tal	1,812	1,716	96	1,641	171		9,471	1,789	23	1,553	259	2,048	1,90

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

Total Unassigned Reserves

(Tons in millions)

	Total Unassigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus) <1.2	1.2-2.5	>2.5	As Received Btus per lb.(1)	Reserve Control Leased	Owned	Mining Method Surface	Underground
Wyoming	390	294	96	342	48		9,664	299	91	216	174
Utah	71	19	52	37	34		11,438	71			71
Colorado	30	24	6	28	2		11,458	30			30
Central App	160	120	40	34	105	21	12,714	127	33	37	123
Illinois	374	269	105			374	11,606	56	318	2	372
Total	1,025	726	299	441	189	395	11,024	583	442	255	770

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

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 73.4% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btus upon combustion, while an additional 8.7% 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, 2008 was $1.2 billion, consisting of $110.7 million of prepaid royalties and a net book value of coal lands and mineral rights of $1.1 billion.

Reserve Acquisition Process

We acquire a significant portion of the coal we control in the western United States through LBA process. Under this process, before a mining company can obtain new coal reserves, the coal tract must be nominated for lease, and the company must win the lease through a competitive bidding process. The LBA process can last anywhere from two to five years from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves.

To initiate the LBA process, companies wanting to acquire additional coal must file an application with the BLM s state office indicating interest in a specific coal tract. The BLM reviews the initial application to determine whether the application conforms to existing land-use plans for that particular tract of land and that the application would provide for maximum coal recovery. The application is further reviewed by a regional coal team at a public meeting. Based on a review of the available information and public comment, the regional coal team will make a recommendation to the BLM whether to continue, modify or reject the application.

If the BLM determines to continue the application, the company that submitted the application will pay for a BLM-directed environmental analysis or an environmental impact statement to be completed. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other governmental agencies during this process, including state and federal agencies, surface management agencies, Native American tribes or bands, the U.S. Department of Justice or others as needed. The public comment period for an analysis or impact statement typically occurs over a 60-day period.

After the environmental analysis or environmental impact statement has been issued and a recommendation has been published that supports the lease sale of the LBA tract, the BLM schedules a public competitive lease sale. The BLM prepares an internal estimate of the fair market value of the coal that is based on its economic analysis and comparable sales analysis. Prior to the lease sale, companies interested in acquiring the lease must send sealed bids to the BLM. The bid amounts for the lease are payable in five annual installments, with the first 20% installment due when the mining operator submits its initial bid for an LBA. Before the lease is approved by the BLM, the company must first furnish to the BLM an initial rental payment for the first year of rent along with either a bond for the next 20% annual installment payment for the bid amount, or an application for history of timely payment, in which case the BLM may waive the bond requirement if the company successfully meets all the qualifications of a timely payor. The bids are opened at the lease sale. If the BLM decides to grant a lease, the lease is awarded to the company that submitted the highest total bid meeting or exceeding the BLM s fair market value estimate, which is not published. The BLM, however, is not required to grant a lease even if it determines that a bid meeting or exceeding the fair market value of the coal has been submitted. The winning bidder must also submit a report setting forth the nature and extent of its coal holdings to the U.S. Department of Justice for a 30-day antitrust review of the lease. If the successful bidder was not the initial applicant, the BLM will refund the initial applicant certain fees it paid in connection with the application process, for example the fees associated with the environmental analysis or environmental impact statement, and the winning bidder will bear those costs. Coal won through the LBA process and subject to federal leases are administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. In addition, we occasionally add small coal tracts adjacent to our existing LBAs through an agreed upon lease modification with the BLM. Once the BLM has issued a lease, the company must also complete the permitting process before it can mine the coal. You should see the section entitled Environmental and Other Regulatory Matters beginning on page 20 for more information about the permitting process.

Most of our federal coal leases have an initial term of 20 years and are renewable for subsequent 10-year periods and for so long thereafter as coal is produced in commercial quantities. These leases require diligent development within the first ten years of the lease award with a required coal extraction of 1.0% of the total coal under the lease by the end of that 10-year period. At the end of the 10-year development period, the lessee is required to maintain continuous operations, as defined in the applicable leasing regulations. In certain cases a lessee may combine contiguous leases into a logical mining unit, which we refer to as an LMU. This allows the production of coal from any of the leases within the LMU to be used to meet the continuous operation requirements for the entire LMU. Some of our mines are also subject to coal leases with applicable state regulatory agencies and have different terms and conditions that we must adhere to in a similar way to our federal leases. Under these federal and state leases, if the leased coal is not diligently developed during the initial 10-year development period or if certain other terms of the leases are not complied with, including the requirement to produce a minimum quantity of coal or pay a minimum production royalty, if applicable, the BLM or the applicable state regulatory agency can terminate the lease prior to the expiration of its term.

Title to Coal Property

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. You should see 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 contained under the heading Risk Factors beginning on page 30 for more information.

At December 31, 2008, approximately 16.4% 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.

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 23,900 acres of property to other coal operators in 2008. We received royalty income of $6.8 million in 2008 from the mining of approximately 3.1 million tons, $5.6 million in 2007 from the mining of approximately 2.1 million tons and $5.0 million in 2006 from the mining of approximately 2.4 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.

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.

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Permit Litigation Matters

Two of our operating subsidiaries were 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 were identified in the suit for having received permits from the Corps. The lawsuit, brought by the Ohio Valley Environmental Coalition in September 2005 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.

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. 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. Both of the district court rulings were appealed to the U.S. Court of Appeals for the Fourth Circuit.

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 injunctions against 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. The claims against Coal-Mac, Inc. were thereafter dismissed.

On February, 13, 2009, the Fourth Circuit reversed the District Court s two orders. The Fourth Circuit held that the Corps jurisdiction under Section 404 of the Clean Water Act is limited to the narrow issue of the filling of jurisdictional waters. The court also held that the Corps findings of no significant impact under the National Environmental Policy Act and no significant degradation under the Clean Water Act are entitled to deference. Such findings entitle the Corps. to avoid an environmental impact statement, the absence of which was one subject of the appeal. These holdings also validated the type of mitigation projects proposed by some of our operations to minimize impacts and comply with the relevant statutes. Finally, the Fourth Circuit found that stream segments, together with the sediment ponds to which they connect, are unitary waste treatment systems, not waters of the United States, and that the Corps had not exceeded its authority in permitting them. Unless the Fourth Circuit shortens or extends the time, the Ohio Valley Environmental Coalition will have until March 30, 2009 to petition for rehearing. Any appeal to the U.S. Supreme Court must be filed by May 14, 2009, unless a petition for rehearing is filed, in which case the time runs from the denial of that petition. The Supreme Court s acceptance of such appeal is discretionary. If no appeal or petition for rehearing is filed, the order will take effect on April 6, 2009. If the Fourth Circuit decision stands, then a backlog of permits pending before the Corps may ease. The impact on our Mingo Logan permit is not yet entirely clear, but it could serve to free that permit for use sooner than anticipated.

West Virginia Flooding Litigation

Over 2,000 plaintiffs have sued us and more than 100 other defendants in Wyoming, 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 of Appeals 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 were initially 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 were initiated, to proceed in phases. On May 2,

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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 trial court set aside that verdict and granted judgment in favor of those defendants. The plaintiffs in that trial group appealed that decision, and on June 26, 2008, the Supreme Court of Appeals reinstated the verdict. The court also reversed the January 18, 2007 dismissal of claims involving the Coal River watershed, in which we are named. Everything was remanded to the Mass Litigation Panel on September 17, 2008. No trial dates are set.

Clean Water Act Request for Information

On January 2, 2008, we received a request from the EPA for certain information related to compliance with effluent limitations and water quality standards under Section 308 of the Clean Water Act applicable to our eastern mining complexes located in West Virginia, Virginia and Kentucky. The request focuses on our compliance with water quality standards and effluent limitations at numerous outfalls as identified in the various NPDES permits applicable to our eastern mining complexes for the period beginning on January 1, 2003 through January 1, 2008. The compliance reporting mechanism is contained in Discharge Monitoring Reports which are required to be prepared and submitted quarterly to state environmental agencies and contain detailed monthly compliance data. In July 2008, the EPA referred the request to the U.S. Department of Justice. We are complying with the request and continue to fully cooperate with the EPA and the U.S. Department of Justice. To date, neither the EPA nor the U.S. Department of Justice has initiated any enforcement action against us.

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 2008.

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 23, 2009, our common stock closed at $12.41 on the New York Stock Exchange. On that date, there were approximately 7,900 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 $48.8 million, or $0.34 per share, in 2008 and $38.7 million, or $0.27 per share, in 2007. 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 58 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.

2008

	March 31	June 30	September 30	December 31
Dividends per common share	$ 0.07	$ 0.09	$ 0.09	$ 0.09
High	56.15	77.40	75.41	32.58
Low	32.98	41.25	27.90	10.43
Close	43.50	75.03	32.89	16.29

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	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

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, 2003;

all dividends were reinvested;

annual reweighting of the peer groups; and

you continued to hold your investment through December 31, 2008.

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					
	2003	2004	2005	2006	2007	2008
Arch Coal, Inc.	$ 100	$ 115	$ 259	$ 197	$ 297	$ 109
S&P 400 (Midcap)	100	116	131	145	156	100
Industry Peer Group	100	176	296	274	495	187

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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, 2008, we have purchased 3,074,200 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, 2008. Based on the closing price of our common stock as reported on the New York Stock Exchange on February 23, 2009, there is approximately $135.6 million of our common stock that may yet be purchased under this program.

ITEM 6. SELECTED FINANCIAL DATA.

	Year Ended December 31				
	2008	2007 (1)	2006 (2) (3)	2005 (2) (3) (4) (5)	2004 (4) (6) (7)
	(Amounts in thousands, except per share data)				
Statement of Operations Data:					
Coal sales revenue	$ 2,983,806	$ 2,413,644	$ 2,500,431	$ 2,508,773	$ 1,907,168
Change in fair value of coal derivatives and trading activities, net	55,093	7,292			
Income from operations	460,389	229,617	336,667	77,857	178,046
Net income	354,330	174,929	260,931	38,123	113,706
Preferred stock dividends		(219)	(378)	(15,579)	(7,187)
Net income available to common stockholders	354,330	174,710	260,553	22,544	106,519
Basic earnings per common share	2.47	1.23	1.83	0.18	0.95
Diluted earnings per common share	2.45	1.21	1.80	0.17	0.89
Balance Sheet Data:					
Total assets	$ 3,978,964	$ 3,594,599	$ 3,320,814	$ 3,051,440	$ 3,256,535
Working capital	46,631	(35,370)	46,471	216,376	355,803
Long-term debt, less current maturities	1,098,948	1,085,579	1,122,595	971,755	1,001,323
Other long-term obligations	491,536	420,819	391,819	382,256	800,332
Stockholders equity	1,728,733	1,531,686	1,365,594	1,184,241	1,079,826
Common Stock Data:					
Dividends per share	$ 0.3400	$ 0.2700	$ 0.2200	$ 0.1600	$ 0.1488
Shares outstanding at year-end	142,833	143,158	142,179	142,573	125,716
Cash Flow Data:					
Cash provided by operating activities	$ 679,137	$ 330,810	$ 308,102	$ 254,607	$ 148,728
Depreciation, depletion and amortization	292,848	242,062	208,354	212,301	166,322
Capital expenditures	497,347	488,363	623,187	357,142	292,605
Dividend payments	48,847	38,945	31,815	27,639	24,043
Operating Data:					

Tons sold	139,595	135,010	134,976	140,202	123,060
Tons produced	133,107	126,624	126,015	129,685	115,861
Tons purchased from third parties	6,037	8,495	10,092	11,226	12,572

(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.

(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. 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.

(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, we sold our remaining investment in Natural Resource Partners in three separate transactions occurring in March, June and October 2004. We recognized an aggregate gain of $91.3 million during 2004.

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. We sell substantially all of our coal to power plants, steel mills and industrial facilities. The locations of our mines enable us to ship coal to most of the major coal-fueled power plants, steel mills and export facilities located in the United States.

Our three reportable business segments are based on the low-sulfur U.S. coal producing regions 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. 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 we mine from underground and surface mines in this region typically has a low sulfur content and varies in heat value. Central Appalachia includes eastern Kentucky, Tennessee, 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, we may sell a portion of the coal we produce in the Central Appalachia region as metallurgical coal, which has high heat content, low expansion pressure, low sulfur content and various other chemical attributes. As such, the prices at which we sell metallurgical coal to customers in the steel industry generally exceed the prices offered by power plants and industrial users for steam coal.

As discussed under the section entitled The Coal Industry, worldwide coal demand continued to increase during 2008, driven by rapid growth in electrical power generation capacity in Asia, particularly in China and India. In the United States, we estimate that electricity generation declined approximately 0.9% in 2008 in response to mild weather and slowing economic activity, particularly during the second half of the year. An increase in international electricity demand had led to increased demand for coal exports from the United States and, during 2008, coal exports for both steam and metallurgical coal increased significantly as demand for U.S. coal in the Atlantic Basin increased. During the second half of 2008, demand for steam and metallurgical coal declined as the United States and most international economies deteriorated. We believe these economic challenges will continue to affect domestic and international demand in 2009. Despite the deterioration in coal index pricing during the second half of 2008, our average realized prices for 2008 were significantly higher than comparable prices for 2007.

In 2009, we expect U.S. power generation to decline more than 1.0% due to weaker domestic and international economic conditions. We also expect U.S. coal consumption to decline in 2009 in response to reduced consumption for electricity generation, lower metallurgical coal demand resulting from global steel production cuts and increased use of natural gas by some electricity generation facilities. As a result of these market pressures, coupled with continued geological challenges, cost pressures, regulatory hurdles and limited access to capital, we expect coal production and capital spending levels across the domestic coal industry will be curtailed. Due to weakening demand in response to challenging domestic economic conditions, we have decreased our estimates of the amount of coal we plan to sell in 2009. In addition, we have decreased our expected capital expenditures for 2009 and have established other process improvement initiatives and cost containment programs.

We estimate that, at December 31, 2008, approximately 21 gigawatts of generating capacity was under construction or in advanced stages of development in the United States. We expect these plants to come online in the next several years, with more than half of these plants to be online by the end of 2010. As such, we anticipate that 2009 will be a transitional year for the U.S. coal industry. Over the intermediate and long-term, we believe coal market fundamentals will be favorable, benefiting from an overall increase in energy use, particularly in developing countries such as China and India.

Items Affecting Comparability of Reported Results

The comparability of our operating results for the years ended December 31, 2008, 2007 and 2006 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 period from January 1, 2007 until June 29, 2007, these 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, these operations contributed coal sales of 4.0 million tons, revenues of $243.8 million and income from operations of $19.5 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.

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. In 2006, we recognized expenses of $8.7 million 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.

West Elk combustion event We idled our West Elk mine in Colorado in the first quarter of 2006 as a result of a combustion-related event that occurred in October 2005. We estimate that the idling resulted in $30.0 million in lost profits during the first quarter of 2006. We also recognized insurance recoveries related to the event of $41.9 million during the year ended December 31, 2006.

Results of Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Summary. Our results during 2008 when compared to 2007 were influenced primarily by stronger market conditions, particularly in the first half of 2008, the impact of our coal trading activities and the elimination of the valuation allowance against deferred tax assets, offset in part by an upward pressure on commodity costs and higher depreciation, depletion and amortization costs.

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Revenues. The following table summarizes information about coal sales during the year ended December 31, 2008 and compares it with the information for the year ended December 31, 2007:

	Year Ended December 31		Increase	
	2008	2007	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
Coal sales	$ 2,983,806	$ 2,413,644	$ 570,162	23.6%
Tons sold	139,595	135,010	4,585	3.4%
Coal sales realization per ton sold	$ 21.37	$ 17.88	$ 3.49	19.5%

Coal sales increased in 2008 from 2007 due to higher price realizations across all segments, a greater percentage of metallurgical coal sales in Central Appalachia and higher sales volumes. 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 beginning on page 53.

Expenses, costs and other. The following table summarizes expenses, costs, changes in fair value of coal derivatives and coal trading activities, net, and other operating income, net for the year ended December 31, 2008 and compares it with the information for the year ended December 31, 2007:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2008	2007	$	%
	(Dollars in thousands)			
Cost of coal sales	$ 2,183,922	$ 1,888,285	$ (295,637)	(15.7)%
Depreciation, depletion and amortization	292,848	242,062	(50,786)	(21.0)
Selling, general and administrative expenses	107,121	84,446	(22,675)	(26.9)
Change in fair value of coal derivatives and coal trading activities, net	(55,093)	(7,292)	47,801	655.5
Other operating income, net	(5,381)	(23,474)	(18,093)	(77.1)
Total	$ 2,523,417	$ 2,184,027	$ (339,390)	(15.5)%

Cost of coal sales. Our cost of coal sales increased from 2007 to 2008 primarily due to higher taxes, royalties and other costs that are sensitive to sales prices ($83.8 million), an increase in transportation costs primarily due to increased barge and export sales ($68.1 million), the increase in sales volumes and higher per-ton production costs in the Powder River Basin. We have provided more information about the results of our operating segments under the heading Operating segment results beginning on page 53.

Depreciation, depletion and amortization. The increase in depreciation, depletion and amortization expense from 2007 to 2008 is due primarily to the costs of capital improvement and mine development projects that we capitalized in 2007 and 2008. We have provided more information about our operating segments under the heading Operating segment results beginning on page 53 and our capital spending in the section entitled Liquidity and Capital Resources beginning on page 58.

Selling, general and administrative expenses. The increase in selling, general and administrative expenses from 2007 to 2008 is due primarily to increases in employee compensation costs of approximately $13.0 million, primarily incentive compensation, industry group dues of approximately $5.0 million and an increase in corporate expenses, including professional fees and travel costs.

Change in fair value of coal derivatives and coal trading activities, net. Net gains in 2008 relate to the net impact of our coal trading activities and the change in fair value of other coal derivatives that have not been designated as hedge instruments in a hedging relationship. Our coal trading function enabled us to take advantage of price movements in the coal markets primarily during the first half of 2008.

Other operating income, net. The decrease in net income from changes in other operating income, net in 2008 compared to 2007 is due primarily to a gain in 2007 of $8.9 million on the disposition of the Mingo

Logan-Ben Creek property and gains in 2007 of $8.4 million related to the sale of non-core reserves in the Powder River Basin and Central Appalachia.

Operating segment results. The following table shows results by operating segment for the year ended December 31, 2008 and compares it with the information for the year ended December 31, 2007:

	Year Ended December 31		Increase (Decrease)	
	2008	2007	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
Powder River Basin				
Tons sold	102,558	99,145	3,413	3.4%
Coal sales realization per ton sold(1)	$ 11.30	$ 10.59	$ 0.71	6.7%
Operating margin per ton sold(2)	$ 1.02	$ 1.23	$ (0.21)	(17.1)%
Western Bituminous				
Tons sold	20,606	19,362	1,244	6.4%
Coal sales realization per ton sold(1)	$ 27.46	$ 24.73	$ 2.73	11.0%
Operating margin per ton sold(2)	$ 5.69	$ 5.11	$ 0.58	11.4%
Central Appalachia				
Tons sold	16,431	16,503	(72)	(0.4)%
Coal sales realization per ton sold(1)	$ 66.73	$ 47.87	$ 18.86	39.4%
Operating margin per ton sold(2)	$ 17.53	$ 3.89	$ 13.64	350.6%

(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, 2008, transportation costs per ton were $0.03 for the Powder River Basin, $4.54 for the Western Bituminous region and $4.02 for Central Appalachia. 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.

(2) Operating margin per ton is calculated as 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 was higher in 2008 when compared to 2007 due primarily to planned production cutbacks in 2007 in response to weak market conditions. Increases in sales prices during 2008 when compared with 2007 reflect higher pricing on contract and market index-priced tons, partially offset by the effect of lower sulfur dioxide emission allowance prices. On a per-ton basis, operating margins in 2008 decreased from 2007 due to an increase in per-ton costs, which offset the contribution of higher sales prices. The increase in per-ton costs resulted primarily from higher diesel fuel and explosives prices, higher sales-sensitive costs, costs related to planned repair and maintenance projects and higher labor costs.

Western Bituminous In the Western Bituminous region, sales volume increased during 2008 when compared with 2007, driven largely by increased demand in the region. Higher sales prices during 2008 when compared with 2007 resulted from higher contract pricing from the roll off of lower-priced legacy contracts and the effect of market-based sales in 2008. Higher sales prices resulted in higher per-ton operating margins for 2008 compared to 2007, partially offset by an increase in transportation costs, depreciation, depletion and amortization and sales-sensitive costs.

In the Western Bituminous Region, we transitioned to a new coal seam at our West Elk mining complex in Colorado in December 2008. We have experienced adverse geologic conditions that have affected production in the new seam and that have reduced the quality of the coal produced. We expect the problems to diminish as we move through the panel and expect the greatest impact on production to occur in the first quarter of 2009.

Central Appalachia Our sales volumes in Central Appalachia were flat during 2008 when compared with 2007 and were affected by the commencement of production at our Mountain Laurel complex at the beginning

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of the fourth quarter of 2007, which offset the impact of the disposition of the Mingo Logan-Ben Creek facility in the second quarter of 2007. Higher realized prices in 2008 reflect the increase in metallurgical coal sales volumes and higher overall pricing on metallurgical and steam coal sales. We sold 4.4 million tons into metallurgical markets in 2008 compared to 2.1 million tons in 2007, and because metallurgical coal generally commands a higher price than steam coal, the increase had a beneficial impact on our average realizations in 2008 when compared to 2007. Operating margins per ton in 2008 increased from 2007 due to the increase in sales prices, net of the impact of higher sales-sensitive costs, and a decrease in other cash costs per ton sold. Our costs of production at Mountain Laurel are lower than our average for the region, which resulted in lower cash costs per ton sold, exclusive of sales-sensitive costs, in 2008 compared to 2007. These margin improvements were partially offset by the effect of higher depreciation, depletion and amortization costs, primarily from Mountain Laurel.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2008 and compares it with the information for the year ended December 31, 2007:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2008	2007	$	%
	(Dollars in thousands)			
Interest expense	$ (76,139)	$ (74,865)	$ (1,274)	(1.7)%
Interest income	11,854	2,600	9,254	355.9
Total	$ (64,285)	$ (72,265)	$ 7,980	11.0%

During 2008, we incurred slightly lower interest costs on borrowings when compared with 2007 as a result of a reduction in our average borrowing rate during 2008. This decrease was offset by a decrease in the amount of interest cost that we capitalized in 2008 when compared to 2007. We capitalized interest costs of $11.7 million during 2008 and $18.0 million during 2007. For more information on our borrowing facilities and ongoing capital improvement and development projects, see Liquidity and Capital Resources beginning on page 58.

Interest income increased as a result of $10.3 million of interest on a black lung excise tax refund we filed in the fourth quarter of 2008. Under law changes related to the Emergency Economic Stabilization Act, we were able to file for a refund of $11.0 million for years that had previously been statutorily closed.

Other non-operating expense. Amounts reported as non-operating consist of income or expense resulting from our financing activities other than interest, including the amortization of previously-deferred amounts from the termination of hedge accounting related to interest rate swaps.

Income taxes. Our effective income tax rate is sensitive to changes in estimates of annual profitability and percentage depletion. The following table summarizes our income taxes for the year ended December 31, 2008 and compares it with information for the year ended December 31, 2007:

Year Ended December 31		Decrease in Net Income	
2008	2007	$	%

	(Dollars in thousands)			
Provision for (benefit from) income taxes	$ 41,774	$ (19,850)	$ 61,624	310.4%

In 2008, our income taxes were impacted by higher profitability, reductions in our valuation allowance against net operating loss and alternative minimum tax credit carryforwards and changes in our effective tax rate when compared with 2007. Income taxes include a $58.0 million reduction in 2008 and a $38.7 million reduction in 2007 in our valuation allowance against net operating loss and alternative minimum tax credit carryforwards that reduced our income taxes. Our effective rate increased from 2007 to 2008, exclusive of the effect of change in the valuation allowance, primarily as a result of the impact of percentage depletion.

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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 recognized 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.

Revenues. The following table summarizes information about coal sales for the year ended December 31, 2007 and compares it with information for the year ended December 31, 2006:

	Year Ended December 31		Increase (Decrease)	
	2007	2006	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
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 beginning on page 56.

Expenses, costs and other. The following table summarizes expenses, costs and other operating income, net for the year ended December 31, 2007 and compares it with 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)
Change in fair value of coal derivatives and coal trading activities, net	(7,292)		7,292	NA
Other operating income, net	(23,474)	(29,800)	(6,326)	(21.2)
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 beginning on page 56.

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 58.

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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.

Change in fair value of coal derivatives and coal trading activities, net. Net gains in 2007 relate to the net impact of our coal trading activities and the change in fair value of other coal derivatives that have not been designated as hedge instruments in a hedging relationship.

Other operating income, net. The decrease 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; 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 it with information for the year ended December 31, 2006:

	Year Ended December 31		Increase (Decrease)	
	2007	2006	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
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 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 it with information for the year ended December 31, 2006:

	Year Ended December 31		Decrease in Net Income	
	2007	2006	$	%
	(Dollars 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 58.

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

	Year Ended December 31		Increase in Net Income	
	2007	2006	$	%
	(Dollars 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 expense includes mark-to-market adjustments related to certain swap activity that did 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.

Liquidity and Capital Resources

Credit crisis and economic environment

The crisis in domestic and international financial markets has had a significant adverse impact on a number of financial institutions. Since the beginning of the crisis, our ability to issue commercial paper up to the maximum amount allowed under the program has been constrained. The ongoing uncertainty in the financial markets may have an impact in the future on: the market values of certain securities and commodities; the financial stability of our customers and counterparties; availability under our lines of credit; the cost and availability of insurance and financial surety programs, and pension plan funding requirements. At this point in time, however, our liquidity has not been materially affected. In response to the current credit markets, we strengthened our liquidity position by building a cash balance of $70.6 million as of December 31, 2008 and by diversifying our borrowings among our lines of credit. While we expect our ability to issue commercial paper will be affected by the current credit markets, we believe we have sufficient liquidity under our credit facilities to satisfy working capital requirements and fund capital expenditures, if needed. We had available borrowing capacity of $641.4 million under our lines of credit at December 31, 2008 in addition to our cash on hand. Management will continue to closely monitor our own liquidity, credit markets and counterparty credit risk. Management cannot predict with any certainty the impact to our liquidity of any further disruption in the credit environment.

Liquidity and capital resources

Our primary sources of cash include sales of our coal production to customers, borrowings under our credit facilities or other financing arrangements, 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. The borrowings under these arrangements are classified as current if the underlying credit facilities expire within one year or if, based on cash projections and management plans, we do not have the intent to replace them on a long-term basis. Such plans are subject to change based on our cash needs.

We believe that cash generated from operations and borrowings under our credit facilities or other financing arrangements will be sufficient to meet working capital requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years. We manage our exposure to changing commodity prices for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements. We enter into fixed price, fixed volume supply contracts with terms greater than one year with customers with whom we have historically had limited collection issues. At December 31, 2008, our expected unpriced production approximated 14 million to 18 million tons in 2009, 55 million to 65 million tons in 2010 and 95 million to 105 million tons in 2011. 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. In response to the economic environment, we have decreased our 2009 capital spending plans and have established other process improvement initiatives and cost containment programs in order to reduce costs.

Our secured revolving credit facility allows for up to $800.0 million of borrowings and expires June 23, 2011. We had borrowings outstanding under the revolving credit facility of $205.0 million at December 31, 2008 and $160.0 million at December 31, 2007. 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, 2008 was 2.70%. 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, 2008. While these financial covenant requirements may restrict the amount of unused capacity available to us for borrowings and letters of credit, as of December 31, 2008, we were not restricted by financial covenants.

We are party to an accounts receivable securitization program whereby eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. During 2008, we entered into an amendment to our accounts receivable securitization program that increased the size of the program from $150.0 million to $175.0 million. The credit facility supporting the borrowings under the program is subject to renewal annually and expires on May 21, 2009. Under the terms of the program, eligible trade receivables consist of trade receivables generated by our operating subsidiaries. Actual borrowing capacity is based on the allowable amounts of accounts receivable as defined under the terms of the agreement. Outstanding borrowings under the program were approximately $68.6 million at December 31, 2008 and $90.8 million at December 31, 2007. 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 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 2.68% at December 31, 2008. 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 had commercial paper outstanding of $65.7 million at December 31, 2008 and $75.0 million at December 31, 2007. Our commercial paper placement program provides 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 $100.0 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 revolving credit facility that is subject to renewal annually with a maturity date of April 30, 2009. As of December 31, 2008, the weighted-average interest rate of our outstanding commercial paper was 2.46% and maturity dates ranged from two to 92 days. The current credit market has affected our ability to issue commercial paper up to the maximum amount allowed under the program, but we believe that the availability under our lines of credit is sufficient to satisfy our liquidity needs.

Our subsidiary, Arch Western Finance LLC, has outstanding an aggregate principal amount of $950.0 million of 6.75% senior notes due on July 1, 2013. The senior notes are guaranteed by Arch Western Resources LLC and certain of its subsidiaries and are secured by an intercompany note from Arch Western Resources, LLC to Arch Coal, Inc. The indenture under which the senior notes were issued contains certain restrictive covenants that limit Arch Western Resources, LLC s ability to, among other things, incur additional debt, sell or transfer assets and make certain investments.

We have filed a universal shelf registration statement on Form S-3 with the SEC 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.

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		
	2008	2007	2006
	(Dollars in thousands)		
Cash provided by (used in):			
Operating activities	$ 679,137	$ 330,810	$ 308,102
Investing activities	(527,545)	(424,995)	(688,005)
Financing activities	(86,023)	96,742	121,925

Cash provided by operating activities was $679.1 million, an increase of $348.3 million in 2008 compared to 2007, primarily as a result of our increased profitability during 2008.

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 used in investing activities for 2008 was $527.5 million, $102.5 million more than was used in investing activities for 2007, primarily the result of proceeds received from asset sales in 2007, as discussed below. 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 2007 and 2008, we made the third and fourth of five annual payments of $122.2 million on the Little Thunder federal coal lease in Wyoming. Additionally, in 2008, we spent approximately $86.5 million on the construction of a new loadout facility at our Black Thunder mine in Wyoming and $132.1 million for the transition to a new reserve area at our West Elk mining complex in Colorado, including the cost of purchasing a new longwall and other mining equipment. We completed the work on the loadout facility and transitioned to the new seam at West Elk in the fourth quarter of 2008. Proceeds from asset sales were $70.3 million during 2007, compared to $1.1 million in 2008. Our proceeds from asset sales in 2007 included $43.5 million related to the sale of the Mingo Logan-Ben Creek complex and $26.0 million from the sale of non-core reserves in the Powder River Basin and Central Appalachia. Cash inflows from investing activities in 2007 also 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.

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. 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, development of the new reserve area at the West Elk mining complex in Colorado, payments for a replacement longwall at our Sufco mining complex in Utah and costs to construct the new loadout at our Black Thunder mining complex. The Mountain Laurel longwall commenced production on October 1, 2007. In 2006, 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 used in financing activities was $86.0 million during 2008 compared to cash provided by financing activities of $96.7 million during 2007. We borrowed, net of repayments, $13.5 million under our commercial paper program and lines of credit during 2008, $120.0 million less than during 2007. During the third quarter of 2008, Standard and Poor s Rating Services raised our corporate credit rating to BB from BB- . At December 31, 2008, debt amounted to $1,312.4 million, or 43% of capital employed, compared to $1,303.2 million, or 46% of capital employed, at December 31, 2007. Based on the level of consolidated indebtedness and prevailing interest rates at December 31, 2008, debt service obligations for 2009, which include the maturities of principal and interest payments, are estimated to be $279.2 million.

During 2008, other financing cash flows included the repurchase of 1.5 million shares of common stock under our share repurchase program at an average price of $35.62 per share. During 2008, we paid dividends of $48.8 million, an increase of $9.9 million when compared to 2007, due to an increase in the dividend rate from $0.06 per share to $0.07 per share in April 2007 and from $0.07 per share to $0.09 per share in April 2008.

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 spent $43.9 million during 2006 under a share repurchase program authorized by the board of directors in September 2006. We increased our dividend rate in April 2006 and 2007 and as a result, dividends paid increased $7.1 million.

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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				
	2008	2007	2006	2005	2004
Ratio of earnings to combined fixed charges and preference dividends[1]	4.90x	2.36x	3.84x	N/A	2.52x

(1) Earnings consist of income from 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.

Contractual Obligations

The following is a summary of our significant contractual obligations as of December 31, 2008:

	Payments Due by Period (Dollars in thousands)				
	2009	2010-2011	2012-2013	After 2013	Total
Long-term debt, including related interest	$ 279,195	$ 271,050	$ 1,046,188	$	$ 1,596,433
Operating leases	33,806	60,783	43,511	38,265	176,365
Coal lease rights	152,895	59,369	19,875	23,302	255,441
Coal purchase obligations	184,019	102,354	123,931	284,630	694,934
Unconditional purchase obligations	173,146				173,146
Total contractual obligations	$ 823,061	$ 493,556	$ 1,233,505	$ 346,197	$ 2,896,319

Our maturities of debt in 2009 include amounts borrowed that are supported by credit facilities that have a term of less than one year and amounts borrowed under credit facilities with terms longer than one year that we do not intend to refinance on a long-term basis, based on cash projections. The related interest on long-term debt was calculated using rates in effect at December 31, 2008 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, the remaining $122.2 million payment due under the Little Thunder lease in Wyoming will be paid in 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 to supply ongoing customer sales commitments.

Unconditional purchase obligations include open purchase orders and other purchase commitments, which have not been recognized as a liability. The commitments in the table above relate to contractual 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 $258.9 million for 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. Asset retirement obligations are recorded at fair value when incurred and accretion expense is recognized through the expected date of settlement. Determining the fair value of asset retirement obligations involves a number of estimates, as discussed in the section entitled Critical Accounting Policies beginning on page 64, including the timing of payments to satisfy the 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 plans and worker s compensation obligations. The timing of contributions to our pension plans varies based on a number of factors, including changes in the fair value of plan assets and actuarial assumptions. You should see the section entitled Critical Accounting Policies beginning on page 64 for more information about these assumptions. In order to achieve a desired funded status, we expect to make contributions of $25.9 million to our pension plans in 2009. This estimate is based on current funding regulations, which are currently under review for potential modification to provide funding relief to companies that sponsor pension plans. 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, 2008:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other	Total
			(Dollars in thousands)		
Self bonding	$ 334,632	$	$	$	$ 334,632
Surety bonds	240,755	51,963	12,700	14,955	320,373
Letters of credit			47,738	12,261	59,999

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. Patriot Coal Corporation acquired Magnum in July 2008, and, as a result, Magnum will be required to post letters of credit in our favor for the full amount of the reclamation obligation on or before February 2011. At December 31, 2008, we had approximately $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, 2008, the cost of purchasing 14.1 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 $200.7 million, and the cost of purchasing 3.7 million tons of coal to supply the assigned and guaranteed contracts over their duration would exceed the sales price under the contracts by approximately $104.7 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 $6.1 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. 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 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 $51.8 million at December 31, 2008. 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.

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:

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. The fair values of the majority of our derivative instruments are obtained from either quoted prices in active markets, quoted prices in over-the-counter markets or direct broker quotes. 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, 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 years ended December 31, 2008 and 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.

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, 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.

Accretion expense is recognized on the obligation through the expected settlement date. Accretion expense was $19.6 million in 2008 and $18.6 million in 2007. 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. Adjustments to the liability resulting from changes in estimates were an increase in the liability of $18.9 million in 2008 and a decrease in the liability of $0.9 million in 2007. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized 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, 2008, we had recorded asset retirement obligation liabilities of $258.9 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, 2008, we estimate that the aggregate undiscounted cost of final mine closure is approximately $666.0 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, the provisions of Statement No. 123R apply to all awards granted or modified after the adoption date. For awards that were granted prior to, but not vested as of, the adoption of Statement No. 123R, we determined unrecognized compensation cost based on the same estimate of the grant-date fair value and the same recognition method used previously under Statement No. 123, which will be reflected in income in periods after adoption. We use the Black-Scholes option pricing model for option valuations and a lattice model for valuations of share-based awards with performance and market conditions that are paid out in stock.

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 or more than the maximum amount that can be deducted for federal income tax purposes. We contributed cash of $2.6 million in 2008 and $2.7 million in 2007 to the plans. 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.

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 2008 and 2007. 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 2008 would have been an increase in expense of approximately $1.1 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 6.5% for 2008 and 5.9% for 2007. The impact of lowering the discount rate 0.5% for 2008 would have been an increase in expense of approximately $2.2 million.

The differences generated from 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 2008, we changed our discount rate to 6.85%.

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. Our current funding policy is to fund the cost of all postretirement 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.

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 6.5% for 2008 and 5.9% for 2007. Had the discount rate been lowered by 0.5% in 2008, we would have incurred additional expense of $0.7 million.

For the measurement of our year-end other postretirement obligation for 2008 and postretirement expense for 2009, we changed our discount rate to 6.85%.

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. We initially recognize the effects of a tax position when it is more than 50 percent likely, based on the technical merits, that the position will be sustained upon examination, including resolution of the related appeals or litigation processes, if any. Our determination of whether or not a tax position has met the recognition threshold considers the facts, circumstances, and information available at the reporting date. A valuation allowance may be recorded to reflect the amount of future tax benefits that management believes are not likely to be realized. We reassess our ability to realize our deferred tax assets annually in the fourth quarter or when circumstances indicate that the ability to realize deferred tax assets has changed. In determining the appropriate valuation allowance, we take into account expected future taxable income and available tax planning strategies. If future taxable income is lower than expected or if expected tax planning strategies are not available as anticipated, we may record additional valuation allowance through income tax expense in the period such determination is made.

Accounting Standards Issued and Not Yet Adopted

In February 2008, the FASB issued Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157*, which we refer to as FSP FAS 157-2, which delays the effective date of Statement No. 157 for nonfinancial assets and nonfinancial liabilities, except for those items that are recognized or disclosed at fair value in the financial statements on a recurring basis. For the items within the scope of Statement No. 157, FSP FAS 157-2 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are assessing the potential impact of Statement No. 157 on the applicable fair value measurements and will adopt FSP FAS 157-2 prospectively on January 1, 2009.

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*, which we refer to as Statement No. 160. Statement No. 160 requires that a noncontrolling interest (minority interest) in a consolidated subsidiary be displayed in the consolidated balance sheet as a separate component of equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the consolidated statement of income for all periods presented. Earnings per share will continue to be calculated based on income attributable to the controlling interest. Noncontrolling interests in our subsidiaries were $9.2 million and $8.3 million at December 31, 2008 and 2007, respectively. Statement No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. Statement No. 160 is effective for fiscal years beginning on or after December 15, 2008. Early adoption is not allowed. We do not expect that the adoption of Statement No. 160 will have a material impact on our financial position or results of operations.

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.

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, 2008, our expected unpriced production approximated 14 million to 18 million tons in 2009, 55 million to 65 million tons in 2010 and 95 million to 105 million tons in 2011.

We are exposed to commodity price risk in our coal trading activities, 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, swap and put and call option contracts at December 31, 2008. With respect to our coal trading positions, a 10% decrease in forward coal prices would cause a $0.9 million decrease in the fair value of these positions. The timing of the estimated future realization of the value of our trading portfolio is 88% in 2009 and 12% in 2010.

We are also exposed to the risk of fluctuations in cash flows related to our purchase of diesel fuel. We use approximately 50 million gallons of diesel fuel annually in our operations. We enter into forward physical purchase contracts, as well as heating oil swaps and options, to reduce volatility in the price of diesel fuel for our operations. At December 31, 2008, we had protected the price of approximately 68% of our forecasted diesel purchases for 2009, 85% of which was accomplished through the use of the derivative instruments noted above. At December 31, 2007, we had protected approximately 23% of our forecasted purchases for 2008. 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, with any ineffectiveness recognized immediately in income. At December 31, 2008, a $0.25 per gallon decrease in the price of heating oil would result in an approximate $6.4 million increase in our expense in 2009 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, 2008, $967.0 million of our outstanding debt had fixed interest rates, primarily our 6.75% Senior Notes, and $339.3 million of outstanding borrowings have interest rates that fluctuate based on changes in the respective market rates. A one percentage point increase in the interest rates related to these borrowings would result in an annualized increase in interest expense of $3.4 million, based on borrowing levels at December 31, 2008.

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, 2008. 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, 2008 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-3 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 2009 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, 2008, Outstanding Equity Awards at December 31, 2008, Option Exercises and Stock Vested for the Year Ended December 31, 2008, Pension Benefits, Nonqualified Deferred Compensation, Potential Payments Upon Termination of Employment or

Change-in-Control and Director Compensation for the Year Ended December 31, 2008 appearing in the section entitled Executive and Director Compensation in our proxy statement to be distributed to stockholders in connection with the 2009 annual meeting.

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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 2009 annual meeting.

Securities Authorized for Issuance Under Equity Compensation Plans

The Arch Coal, Inc. 1997 Stock Incentive Plan, which has been approved by our stockholders, is the sole plan under which we are authorized to issue shares of our common stock to employees. The following table shows the number of shares of common stock to be issued upon vesting of restricted stock units or exercise of options outstanding at December 31, 2008, the weighted average exercise price of options, and the number of shares of common stock remaining available for future issuance at December 31, 2008, excluding shares to be issued upon exercise of outstanding options. No warrants or rights had been issued under the plan as of December 31, 2008.

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	2,997,804	$ 29.10	3,058,129
Equity compensation plans not approved by security holders			
Total	2,997,804	$ 29.10	3,058,129

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 2009 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 2009 annual meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

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

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

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 2008, 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.

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, 2008, 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 23, 2009, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 23, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders Arch Coal, Inc.

We have audited Arch Coal, Inc s (the Company s) internal control over financial reporting as of December 31, 2008, 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, 2008, 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, 2008 and 2007, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008, of Arch Coal, Inc., and our report dated February 23, 2009, expressed an unqualified opinion thereon.

St. Louis, Missouri
February 23, 2009

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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, 2008.

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	John T. Drexler
Chairman and Chief	*Senior Vice President and Chief*
Executive Officer	*Financial Officer*

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	2008	2007	2006
	(In thousands, except per share data)		
REVENUES			
Coal sales	$ 2,983,806	$ 2,413,644	$ 2,500,431
COSTS, EXPENSES AND OTHER			
Cost of coal sales	2,183,922	1,888,285	1,909,822
Depreciation, depletion and amortization	292,848	242,062	208,354
Selling, general and administrative expenses	107,121	84,446	75,388
Change in fair value of coal derivatives and coal trading activities, net	(55,093)	(7,292)	
Other operating income, net	(5,381)	(23,474)	(29,800)
	2,523,417	2,184,027	2,163,764
Income from operations	460,389	229,617	336,667
Interest expense, net:			
Interest expense	(76,139)	(74,865)	(64,364)
Interest income	11,854	2,600	3,725
	(64,285)	(72,265)	(60,639)
Other non-operating expense:			
Expenses resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps		(1,919)	(4,836)
Other non-operating expense		(354)	(2,611)
		(2,273)	(7,447)
Income before income taxes	396,104	155,079	268,581
Provision for (benefit from) income taxes	41,774	(19,850)	7,650
NET INCOME	$ 354,330	$ 174,929	$ 260,931
EARNINGS PER COMMON SHARE			
Basic earnings per common share	$ 2.47	$ 1.23	$ 1.83
Diluted earnings per common share	$ 2.45	$ 1.21	$ 1.80
Basic weighted average shares outstanding	143,604	142,518	142,770
Diluted weighted average shares outstanding	144,416	144,019	144,812
Dividends declared per common share	$ 0.34	$ 0.27	$ 0.22

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

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CONSOLIDATED BALANCE SHEETS

	December 31 2008	December 31 2007
	(In thousands, except per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 70,649	$ 5,080
Trade accounts receivable	215,053	229,965
Other receivables	43,419	19,724
Inventories	191,568	177,785
Prepaid royalties	43,780	22,055
Deferred income taxes	52,918	18,789
Coal derivative assets	43,173	7,743
Other	45,818	40,004
Total current assets	706,378	521,145
Property, plant and equipment:		
Coal lands and mineral rights	1,818,657	1,690,176
Plant and equipment	2,031,561	1,729,501
Deferred mine development	762,746	672,496
	4,612,964	4,092,173
Less accumulated depreciation, depletion and amortization	(1,909,881)	(1,628,535)
Property, plant and equipment, net	2,703,083	2,463,638
Other assets:		
Prepaid royalties	66,918	105,106
Goodwill	46,832	40,032
Deferred income taxes	294,682	296,559
Equity investments	87,761	82,950
Other	73,310	85,169
Total other assets	569,503	609,816
Total assets	$ 3,978,964	$ 3,594,599
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 186,322	$ 150,026
Coal derivative liabilities	10,757	
Accrued expenses and other current liabilities	249,203	188,875
Current maturities of debt and short-term borrowings	213,465	217,614

Total current liabilities	659,747	556,515
Long-term debt	1,098,948	1,085,579
Asset retirement obligations	255,369	219,991
Accrued pension benefits	73,486	8,528
Accrued postretirement benefits other than pension	58,163	59,181
Accrued workers compensation	30,107	41,071
Other noncurrent liabilities	74,411	92,048
Total liabilities	2,250,231	2,062,913
Stockholders equity:		
Preferred stock, $0.01 par value, authorized 10,000 shares, issued and outstanding 0 and 85 shares at December 31, 2008 and 2007, respectively		1
Common stock, $0.01 par value, authorized 260,000 shares, issued 144,345 and 143,158 shares at December 31, 2008 and 2007, respectively	1,447	1,436
Paid-in capital	1,381,496	1,358,695
Treasury stock, 1,512 shares at December 31, 2008, at cost	(53,848)	
Retained earnings	478,734	173,186
Accumulated other comprehensive loss	(79,096)	(1,632)
Total stockholders equity	1,728,733	1,531,686
Total liabilities and stockholders equity	$ 3,978,964	$ 3,594,599

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, 2008

	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, 2006	$ 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		
Effect of adoption of EITF 04-6				(26,061)				(26,061)
Effect of adoption of Statement No. 158							(11,949)	(11,949)
Effect of adoption of Statement No. 123R			(9,947)		9,947			
BALANCE AT DECEMBER 31, 2006	2	1,426	1,345,188	38,147			(19,169)	1,365,594
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	(1)	3	(2)					

conversion of preferred stock						
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
Comprehensive income:						
Net income				354,330		354,330
Pension, postretirement and other post-employment benefits					(31,907)	(31,907)
Net amount reclassified to income					(684)	(684)
Unrealized losses on available-for- sale securities					(349)	(349)
Net amount reclassified to income					1,005	1,005
Unrealized losses on derivatives					(44,128)	(44,128)
Net amount reclassified to income					(1,401)	(1,401)
Total comprehensive income						276,866
Dividends:						
Common ($0.34 per share)				(48,769)		(48,769)
Preferred ($2.50 per share)				(12)		(12)
Issuance of 261 shares of common stock under the stock incentive plan restricted stock and restricted stock units		2	(2)			
Issuance of 405 shares of common stock upon conversion of preferred stock	(1)	4	(3)			
Preferred stock redemption			(24)	(1)		(25)
		5	6,314			6,319

Issuance of 521 shares of common stock under the stock incentive plan stock options including income tax benefits								
Employee stock-based compensation expense			16,516					16,516
Purchase of 1,512 shares of common stock under stock repurchase program						(53,848)		(53,848)
BALANCE AT DECEMBER 31, 2008	$	$ 1,447	$ 1,381,496	$ 478,734	$	$ (53,848)	$ (79,096)	$ 1,728,733

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2008	2007	2006
	(In thousands)		
OPERATING ACTIVITIES			
Net income	$ 354,330	$ 174,929	$ 260,931
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	292,848	242,062	208,354
Prepaid royalties expensed	36,227	11,962	9,045
Net (gain) loss on dispositions of property, plant and equipment	(243)	(17,769)	649
Gain on investment in Knight Hawk Holdings, LLC			(10,309)
Employee stock-based compensation	12,618	5,777	9,080
Other non-operating expense		2,273	7,447
Changes in operating assets and liabilities:			
Receivables	(9,871)	10,254	(49,265)
Inventories	(13,783)	(55,471)	(39,783)
Coal derivative assets and liabilities	(41,183)	(8,532)	
Accounts payable, accrued expenses and other current liabilities	21,823	(59,634)	(115,123)
Deferred income taxes	15,222	(31,825)	20,505
Accrued postretirement benefits other than pension	4,202	3,733	8,662
Asset retirement obligations	16,437	21,609	10,967
Accrued workers compensation	(528)	971	(2,898)
Other	(8,962)	30,471	(10,160)
Cash provided by operating activities	679,137	330,810	308,102
INVESTING ACTIVITIES			
Capital expenditures	(497,347)	(488,363)	(623,187)
Proceeds from dispositions of property, plant and equipment	1,135	70,296	777
Additions to prepaid royalties	(19,764)	(19,713)	(20,062)
Purchases of investments/advances to affiliates	(7,466)	(5,540)	(45,533)
Consideration paid related to prior business acquisitions	(6,800)		
Reimbursement of deposit on equipment	2,697	18,325	
Cash used in investing activities	(527,545)	(424,995)	(688,005)
FINANCING ACTIVITIES			
Net proceeds from commercial paper and net borrowings on lines of credit	13,493	133,476	192,300
Net proceeds from (payments on) other debt	(2,907)	(2,696)	442
Debt financing costs	(233)	(202)	(2,171)
Dividends paid	(48,847)	(38,945)	(31,815)
Purchases of treasury stock	(53,848)		(43,876)
Issuance of common stock under incentive plans	6,319	5,109	7,045

Cash provided by (used in) financing activities		(86,023)		96,742		121,925
Increase (decrease) in cash and cash equivalents		65,569		2,557		(257,978)
Cash and cash equivalents, beginning of year		5,080		2,523		260,501
Cash and cash equivalents, end of year	$	70,649	$	5,080	$	2,523
SUPPLEMENTAL CASH FLOW INFORMATION:						
Cash paid during the year for interest	$	(71,620)	$	(69,866)	$	(59,116)
Cash (paid) received during the year for income taxes	$	(22,830)	$	2,145	$	8,921

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.

Accounting Pronouncements Adopted

On January 1, 2008, the Company adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* (Statement No. 157) prospectively for the Company s financial instruments. 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. The issuance of FSP FAS 157-2, *Effective Date of FASB Statement No. 157* (FSP FAS 157-2) 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 will adopt FSP FAS 157-2 prospectively on January 1, 2009.

Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (Statement No. 159) became effective January 1, 2008. Statement No. 159 permits entities the choice to measure certain financial instruments and other items at fair value. The Company has not elected to measure any additional financial instruments or other items at fair value.

On January 1, 2008, the Company adopted Staff Position FIN 39-1, *Amendment of FASB Interpretation 39* (FSP FIN 39-1). FSP FIN 39-1 permits a reporting entity to offset fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. The Company did not elect to net amounts related to cash collateral with the fair value of derivatives with the same counterparty. The Company had a current asset for the right to reclaim cash collateral of $6.6 million at December 31, 2008 and had a current liability for the obligation to return cash collateral of $3.0 million at December 31, 2007.

In September 2008, the FASB issued Staff Position FAS 133-1 and FIN 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161* (FSP FAS 133-1 and FIN 45-4), which became effective in December 2008. FSP FAS 133-1 and FIN 45-4 is intended to improve disclosures about credit derivatives and guarantees, primarily the disclosure of the current status of the payment/performance risk of the guarantee, and to clarify the effective date of Statement No. 161. The Company has included the required disclosure related to the payment/performance risk of its guarantees in Note 20, Guarantees below.

In October 2008, the FASB issued Staff Position FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP FAS 157-3), effective upon issuance. FSP FAS 157-3 clarifies the application of FASB Statement No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

asset is not active. The Company s current fair value measurements were not affected by the issuance of FSP FAS 157-3.

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. At December 31, 2008 and 2007, the carrying amounts of cash and cash equivalents approximate fair value.

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 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 at December 31, 2008 and 2007, 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 operating income, 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. A decline in the value of an investment which is other than temporary is recognized in income.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $3.2 million and $3.5 million at December 31, 2008 and 2007, 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 $0.3 million and $1.3 million at December 31, 2008 and 2007, 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, $0.3 million and $1.0 million in 2008, 2007 and 2006, respectively. Amortization income on all below-market coal supply agreements was $1.0 million, $1.9 million and $11.8 million in 2008, 2007 and 2006, respectively.

Exploration Costs

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

Property, Plant and Equipment

Plant and Equipment

Plant and equipment are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. During the years ended December 31, 2008, 2007 and 2006, interest costs of $11.7 million, $18.0 million and $14.8 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. Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation. Other plant and equipment are depreciated principally on the straight-line method over the estimated useful lives of the assets, limited by the remaining life of the mine. The useful lives of mining equipment, including longwalls, draglines and shovels, range from 3 to 32 years. The useful lives of buildings and leasehold improvements generally range from 10 to 30 years.

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 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

50 years), and substantially all of the leases contain provisions that allow for automatic extension of the lease term providing certain requirements are met. The net book value of the Company s leased coal interests was $1.1 billion and $1.0 billion at December 31, 2008 and 2007, 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 installments of $122.2 million in 2006, 2007 and 2008, with the last remaining annual payment to be paid in 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 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 (DCF) analysis. A number of significant assumptions and estimates are involved in the application of the DCF analysis to forecast operating cash flows, including the discount rate, the internal rate of return, and projections of realizations and costs to produce. Management considers historical experience and all available information at the time the fair values of its reporting units are estimated.

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. The unamortized balance of deferred financing costs was $15.7 million and $20.2 million at December 31, 2008 and 2007, respectively. Amounts classified as current were $4.6 million and $4.7 million at December 31, 2008 and 2007, 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, Net

Other operating income, net in the accompanying consolidated statement s of income reflects income and expense from sources other than coal sales, including royalties earned from properties leased to third parties;

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

income from equity investments; gains and losses from dispositions of assets; and realized gains and losses on derivatives that do not qualify for hedge accounting and are not held for trading purposes.

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. Accretion expense is recognized through the expected settlement date of the obligation. 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 based upon permit requirements and various estimates and assumptions, including estimates of disturbed acreage, reclamation costs and assumptions regarding productivity. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying value 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 utilizes derivative financial instruments to manage exposures to commodity prices. 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 and classified in a manner consistent with the transaction being hedged. The Company formally documents the relationships between hedging instruments and the respective hedged items, as well as its risk management objectives for hedge transactions.

The Company evaluates the effectiveness of its hedging relationships both at the hedge s inception and on an ongoing basis. Any ineffective portion of a cash flow hedge s change in fair value, based on the extent to which exact offset is not achieved between the change in fair value of the hedge instrument and the cumulative change in expected future cash flows on the hedged transaction from inception of the hedge, is recognized immediately in earnings. The amount of ineffectiveness recognized in other operating income, net in the accompanying consolidated statements of income resulting from heating oil derivatives was a gain of $1.4 million for the year ended December 31, 2007. Ineffectiveness was insignificant for the years ended December 31, 2008 and 2006.

Income Taxes

Deferred income taxes are provided for temporary differences arising from differences between the financial statement amount and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates anticipated 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 need for a 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 most 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 through 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 Note 13, Employee Benefit Plans for additional disclosures relating to these obligations.

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, the provisions of Statement No. 123R apply to all awards granted or modified after the adoption date. For awards that were granted prior to, but not vested as of, the adoption of Statement No. 123R, unrecognized compensation cost was determined based on the same estimate of the grant-date fair value and the same recognition method used previously under Statement No. 123 and will be reflected in income in periods after adoption. The effects of adoption on retained earnings, net income and the consolidated statement of cash flows for the year ended December 31, 2006 was insignificant. See further discussion in Note 16, Stock Based Compensation and Other Incentive Plans.

Accounting Standards Issued and Not Yet Adopted

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (Statement No. 160). Statement No. 160 requires that a noncontrolling interest (minority interest) in a consolidated subsidiary be displayed in the consolidated balance sheet as a separate component of equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the consolidated statement of income for all periods presented. Noncontrolling interests in the Company s subsidiaries were $9.2 million and $8.3 million at December 31, 2008 and 2007, respectively. Statement No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. Statement No. 160 is effective for fiscal years beginning on or after December 15, 2008. Early adoption is not allowed. The Company does not expect that the adoption of Statement No. 160 will have a material impact on the Company s financial position or results of operations.

In February 2008, the FASB issued Staff Position FAS 140-3, *Accounting for Transfers of Financial Assets and Repurchase Financing Transactions,* which provides guidance on accounting for a transfer of a financial asset and a repurchase financing. This FSP presumes that an initial transfer of a financial asset and a repurchase financing are considered part of the same arrangement under Statement 140. However, if certain criteria are met, the initial transfer and repurchase financing shall not be evaluated as a linked transaction and shall be evaluated separately under Statement 140. This FSP is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application not permitted. The Company is assessing FSP FAS 140-3 to determine its impact, if any, on the financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In February 2008, the FASB issued Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157*, which delays the effective date of Statement 157 for nonfinancial assets and nonfinancial liabilities, except for those items that are recognized or disclosed at fair value in the financial statements on a recurring basis. For the items within scope of Statement 157, FSP FAS 157-2 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company is assessing the potential impact of Statement No. 157 on the applicable fair value measurements.

In March 2008, the FASB issued Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* (Statement No. 161). Statement No. 161 requires additional disclosures about derivatives and hedging activities, including qualitative disclosures about objectives for using derivatives. It also requires tabular disclosures about gross fair value amounts of derivative instruments, gains and losses on derivative instruments by type of contract, and the locations of these amounts in the financial statements. Statement No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. The Company is currently assessing Statement No. 161 to determine the impact of the new disclosure requirements.

In June 2008, the FASB issued Staff Position No. EITF 03-6-01 *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1) to clarify whether instruments granted in share-based payment transactions are participating securities prior to vesting and therefore need to be included in the earnings allocation in computing earnings per share under the two-class method. FSP EITF 03-6-1 is effective retrospectively for the Company for financial statements issued for interim periods of fiscal years beginning after December 15, 2008, and earlier application is not permitted. The Company does not expect FSP EITF 03-6-1 to have a significant impact on earnings per share.

In November 2008, the EITF issued Issue 08-6, *Accounting for Equity Method Investments* (EITF 08-6), because of questions raised regarding the application of the equity method. EITF 08-6 concludes that equity method investments should be recognized using a cost accumulation model and that the investments as a whole should be assessed for other-than-temporary impairment in accordance with APB-18 and not at the investor level. EITF 08-6 also concludes that gains or losses on issuance of shares by the investee should be accounted for and reflected in the income statement of the equity method investor as if the investor had sold part of his investment. EITF 08-6 also sets out how companies will account for the loss of significant influence such that the accounting method for the investment must change from the equity method to the cost method in accordance with APB 18 or FASB Statement 115. EITF 08-06 is effective on a prospective basis for transactions in an investee s shares occurring or impairments recognized in fiscal years, and interim periods, beginning after December 15, 2008, with early application not permitted. The Company does not expect EITF-08-6 to have a significant impact on the accounting for its equity investments.

In December 2008, the FASB issued Staff Position FAS 132 (R)-1, *Employers Disclosures about Pensions and Other Postretirement Benefits* (FSP FAS 132(R)-1), to require additional disclosures about assets held in an employer s defined benefit pension or other postretirement plan. The FSP requires companies to disclose the fair value of each major asset type by levels that categorize the inputs used in valuation and a reconciliation of the beginning and ending balances of plan assets with fair values measured using significant unobservable inputs. FSP 132 (R)-1 is effective for the Company for financial statements issued for fiscal years ending after December 31, 2009. The Company is assessing FSP FAS 132 (R)-1 to determine the impact of the new disclosure requirements.

2. Property Transactions

On September 28, 2007, the Company purchased coal reserves and surface rights in Illinois for $38.9 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and 2006, the Company s Mingo Logan-Ben Creek operations contributed coal sales of 1.2 million and 4.0 million tons, revenues of $75.1 million and $243.8 million and income from operations of $9.1 million and $19.5 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, 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 could not 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 Coal Company (Magnum) under the Purchase and Sale Agreement (the Purchase Agreement). The gain recorded in 2005 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 not be sourced from the Company s operations as a result of the transaction. As the Company shipped coal during 2006 to satisfy the below-market contracts, the liability was relieved against cost of coal sales. The Company paid $50.2 million to Magnum in 2006 to purchase this coal and to offset certain ongoing operating expenses of Magnum. 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. In accordance with the Purchase Agreement, the Company agreed to various guarantees which are described in Note 20, Guarantees.

During the years ended December 31, 2008, 2007 and 2006, gains (losses) on other dispositions of property, plant and equipment were $0.2 million, $8.9 million and $(0.6) million, respectively. Included in the gain for 2007 was $8.4 million related to the sales of non-strategic reserves in the Powder River Basin and Central Appalachia.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006	$ (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)
2008 activity, before tax	(71,129)		(50,925)	1,024	(121,030)
2008 activity, tax effect	25,600		18,334	(368)	43,566
Balance December 31, 2008	$ (45,249)	$	$ (33,433)	$ (414)	$ (79,096)

As discussed in Note 1, Accounting Policies unrealized gains or 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 associated with recognizing 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, 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 $6.4 million, $3.6 million and $2.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. At December 31, 2008 and 2007, the Company had an investment in Knight Hawk of $48.1 million and $43.9 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 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 $1.8 million, $1.6 million and $0.1 million for the years ended December 31, 2008, 2007

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and 2006, respectively. At December 31, 2008 and 2007, the Company had an investment in DKRW of $25.1 million and $26.9 million, respectively.

In 2008, the Company entered into a convertible secured promissory note with DKRW where DKRW may borrow up to $10.0 million from time to time. Amounts borrowed are due and payable in cash or in additional equity interests on the earlier of May 1, 2010 or upon the closing of DKRW s next financing, bears interest at the rate of 1% per month, is convertible into securities issued by DKRW in connection with its next financing and is secured by DKRW s equity interests in Medicine Bow Fuel & Power LLC. As of December 31, 2008, the Company had advanced $3.0 million under the note.

The Company holds a 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. DTA leases the facility from Peninsula Ports Authority of Virginia (PPAV) for amounts sufficient to meet debt-service requirements. 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. During 2008, the Company increased its interest from 17.5% to approximately 21.9%. The Company s portion of DTA s costs was $3.6 million, $3.1 million and $2.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. At December 31, 2008 and 2007, the Company had an investment in DTA of $14.5 million and $12.1 million, respectively.

5. Inventories

Inventories consist of the following:

	December 31 2008	2007
	(In thousands)	
Coal	$ 64,683	$ 61,656
Repair parts and supplies	126,885	116,129
	$ 191,568	$ 177,785

The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $12.7 million and $13.5 million at December 31, 2008 and 2007, respectively.

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 purchases approximately 50 million gallons of diesel fuel annually in its operations. To reduce volatility in the price of diesel fuel for its operations, the Company uses forward physical diesel purchase contracts, as well as heating oil swaps and purchased call options, because the changes in the price of heating oil highly correlate to changes in the price of its hedged purchases. Accordingly, the heating oil swaps and purchased call options qualify for hedge accounting and the changes in the fair value of the derivatives are recorded through other comprehensive income. At December 31, 2008, the Company had protected the price of approximately 68% of its purchases for fiscal year 2009 and 10% of its purchases for fiscal year 2010. Approximately 85% of the 2009 hedges have been accomplished through the use of heating oil swaps and purchased call options. The fair value of these derivatives was a current liability of $51.8 million at December 31, 2008, and a current asset of $2.0 million at December 31, 2007.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Coal trading positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market for trading purposes. The fair value of these positions was a net asset of $39.1 million and $8.5 million at December 31, 2008 and 2007, respectively. The timing of the estimated future realization of the value of the trading portfolio is 88% in 2009 and 12% in 2010. These coal trading assets and liabilities are classified as coal derivative assets and coal derivative liabilities in the accompanying consolidated balance sheets. Gains and losses from trading activities are recognized in income.

Coal risk management positions

The Company may sell or purchase forward contracts and options in the over-the-counter coal market in order to manage its exposure to coal prices. The fair value of these derivative instruments are included in coal derivative assets and coal derivative liabilities in the accompanying consolidated balance sheets. Certain contracts may be designated as the hedge instrument in a hedging relationship, and the changes in value are recorded in other comprehensive income. Losses of $14.2 million are expected to be reclassified from other comprehensive income into earnings in 2009, based on fair values at December 31, 2008.

Interest rate risk management

In the fourth quarter of 2005, the Company terminated certain interest rate swap agreements that at one time had been designated as a hedge of interest rate volatility on floating rate debt. The amounts that had been deferred in accumulated other comprehensive income were amortized as additional expense over the contractual terms of the swap agreements prior to their termination. For the years ended December 31, 2007 and 2006, the Company recognized $1.9 million and $4.8 million of expense, respectively, related to the amortization of the balance in other comprehensive income.

7. Accrued Expenses and Other Current Liabilities

Accrued expenses included in current liabilities consist of the following:

	December 31 2008	December 31 2007
	(In thousands)	
Payroll and employee benefits	$ 53,134	$ 48,990
Taxes other than income taxes	92,682	77,810
Interest	33,168	33,478
Heating oil derivatives (see Note 6)	51,770	
Workers compensation (see Note 12)	6,964	6,973
Asset retirement obligations (see Note 11)	3,482	4,530
Other	8,003	17,094
	$ 249,203	$ 188,875

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Taxes

Income taxes

The Company is subject to U.S. federal income tax as well as income tax in multiple state jurisdictions. The tax years 2004 through 2008 remain open to examination for U.S. federal income tax matters and 1998 through 2008 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		
	2008	2007	2006
	(In thousands)		
Current:			
Federal	$ 24,066	$ 3,687	$ 1,213
State	1,027		
Total current	25,093	3,687	1,213
Deferred:			
Federal	35,545	(20,090)	22,700
State	(18,864)	(3,447)	(16,263)
Total deferred	16,681	(23,537)	6,437
	$ 41,774	$ (19,850)	$ 7,650

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		
	2008	2007	2006
	(In thousands)		
Income tax expense at statutory rate	$ 138,637	$ 54,278	$ 94,003
Percentage depletion allowance	(45,336)	(36,028)	(38,754)
State taxes, net of effect of federal taxes	4,060	569	1,576
Change in valuation allowance	(57,973)	(38,681)	(49,129)
Other, net	2,386	12	(46)
	$ 41,774	$ (19,850)	$ 7,650

In 2008, 2007 and 2006, compensatory stock options and other equity based compensation awards were exercised resulting in a tax benefit of $9.8 million, $5.6 million and $7.9 million, respectively, which will be recorded to paid-in capital at such point in time when a cash tax benefit is recognized.

During 2006, the tax effect of the adoption of EITF 04-6 relating to the accounting for 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	
	2008	2007
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 120,291	$ 154,222
Plant and equipment	22,016	104,774
Alternative minimum tax credit carryforwards	125,744	98,900
Reclamation and mine closure	49,612	42,790
Workers compensation	17,634	19,633
Derivatives	19,224	445
Advance royalties	27,447	17,766
Postretirement benefits other than pension	37,235	15,195
Other	57,288	57,176
Gross deferred tax assets	476,491	510,901
Valuation allowance	(395)	(69,326)
Total deferred tax assets	476,096	441,575
Deferred tax liabilities:		
Deferred development	59,401	57,884
Investment in tax partnerships	50,913	56,209
Other	18,182	12,134
Total deferred tax liabilities	128,496	126,227
Net deferred tax asset	347,600	315,348
Less current asset	52,918	18,789
Long-term deferred tax asset	$ 294,682	$ 296,559

The Company has net operating loss carryforwards for regular income tax purposes of $120.3 million at December 31, 2008 that will expire from 2009 to 2027. The Company has an alternative minimum tax credit carryforward of $125.7 million at December 31, 2008, which has no expiration date and can be used to offset future regular tax in excess of the alternative minimum tax.

During 2008, the Company reached a settlement with the IRS regarding 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. The settlement did not result in a net change in deferred tax assets, but involved a re-characterization of deferred tax assets, including an increase in net operating loss carryforwards of $145.1 million and other amortizable assets which will provide additional tax deductions through 2013. A portion of the cash tax benefits associated with these additional tax deductions accrue to ARCO pursuant to the original purchase agreement, including $6.8 million that was paid in 2008 and recorded as goodwill.

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 $68.9 million during the year ended December 31, 2008 and $44.7 million during the year ended December 31, 2007. Management reassesses the ability to realize its deferred tax assets annually in the fourth quarter or when circumstances indicate that the ability to realize deferred tax assets has changed. In determining the appropriate valuation

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

allowance, the assessment takes into account expected future taxable income and available tax planning strategies. This review resulted in decreases in the valuation allowance of $61.9 million, $44.7 million and $49.1 million in 2008, 2007 and 2006, respectively. Of the decreases in 2008 and 2007, $3.9 million and $2.6 million, respectively, were recorded in paid in capital associated with the exercise of compensatory stock options. Also during 2008, the valuation allowance was reduced $7.0 million relating to state net operating losses that were lost as a result of changes to West Virginia s income tax laws during the year. The remaining valuation allowance of $0.4 million relates to certain state net operating loss benefits.

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

Balance at December 31, 2007	$ 4,070
Additions based on tax positions related to the current year	122
Additions for tax positions of prior years	909
Reductions for tax positions of prior years	(223)
Balance at December 31, 2008	$ 4,878

If recognized, $4.9 million of the gross unrecognized tax benefits at December 31, 2008 would affect the effective tax rate. No gross unrecognized tax benefits are expected to be reduced in the next 12 months due to the expiration of the statute of limitations.

Other taxes

The Emergency Economic Stabilization Act (the Act) enacted on October 3, 2008 enabled certain coal producers to file for refunds of black lung excise taxes paid on export sales subsequent to October 1, 1990, along with interest computed at statutory rates. The Company filed for a refund under the Act and recognized a refund of $11.0 million plus interest of $10.3 million in the fourth quarter of 2008.

9. Debt and Financing Arrangements

Debt consists of the following:

	December 31	
	2008	2007
	(In thousands)	
Commercial paper	$ 65,671	$ 74,959
Indebtedness to banks under credit facilities	273,597	250,816
6.75% senior notes ($950.0 million face value) due July 1, 2013	956,148	957,514
Other	16,997	19,904
	1,312,413	1,303,193
Less current maturities and short-term borrowings	213,465	217,614

Long-term debt	$ 1,098,948	$ 1,085,579

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 commercial paper program, the Company may sell interest-bearing or discounted short-term unsecured debt obligations with maturities of no more than 270 days. Market conditions may impact the Company s ability to issue commercial paper. The Company amended the program on April 11, 2008 to increase the maximum aggregate principal amount outstanding to $100.0 million from $75.0 million. The commercial paper placement program is supported by a revolving credit facility, which is subject to renewal

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

annually, and expires on April 30, 2009. As of December 31, 2008, the weighted-average interest rate of the Company s outstanding commercial paper was 2.46% and maturity dates ranged from 2 to 92 days.

The Company has a secured revolving credit facility that allows for up to $800.0 million in borrowings, expiring on June 23, 2011. 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, 2008 and 2007, borrowings of $205.0 million and $160.0 million, respectively, were outstanding under the credit facility. At December 31, 2008, the Company had $595.0 million of unused borrowings under the revolver. As of December 31, 2008, the weighted-average interest rate of the Company s outstanding borrowings under the credit facility was 2.70%. 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, 2008, the Company was not restricted by financial covenants.

On February 10, 2006, the Company established an accounts receivable securitization program under which 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 under the program. On May 22, 2008, the Company entered into an amendment to its accounts receivable securitization program that increased the size of the program from $150.0 million to $175.0 million. Available borrowing capacity is based on the allowable amount of accounts receivable as defined under the terms of the agreement. The credit facility supporting the borrowings under the program is subject to renewal annually and expires May 22, 2009. The interest rate in effect as of December 31, 2008 was 2.68%. As of December 31, 2008 and 2007 borrowings of $68.6 million and $90.8 million, respectively, were outstanding under the program. At December 31, 2008, the Company had available borrowing capacity under the program of $46.4 million.

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 an intercompany note from Arch Western to Arch Coal, Inc. 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.

Current maturities of debt include amounts borrowed that are supported by credit facilities that have a term of less than one year and amounts borrowed under credit facilities with terms longer than one year that the Company does not intend to refinance on a long-term basis, based on cash projections and management s plans.

Expected aggregate maturities of debt are $213.5 million in 2009, $0 in 2010, $142.8 million in 2011, $0 in 2012 and $950.0 in 2013.

At December 31, 2008 and 2007, the fair value of the Company s senior notes and other long-term debt, including amounts classified as current, was $1,178.0 million and $1,276.9 million, respectively.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008.

10. Fair Values of Financial Instruments

Statement No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy, as defined below, gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs.

Level 1 is defined as observable inputs such as quoted prices in active markets for identical assets. Level 1 assets include available-for-sale equity securities and coal futures that are submitted for clearing on the New York Mercantile Exchange.

Level 2 is defined as observable inputs other than Level 1 prices. These include quoted prices for similar assets or liabilities in an active market, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. The Company s level 2 assets and liabilities include commodity contracts (coal and heating oil) with quoted prices in over-the-counter markets or direct broker quotes.

Level 3 is defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. These include the Company s commodity option contracts (primarily coal and heating oil) valued using modeling techniques, such as Black-Scholes, that require the use of inputs, particularly volatility, that are not observable.

The table below sets forth, by level, the Company s financial assets and liabilities that are accounted for at fair value:

	Fair Value at December 31, 2008			
	Total	Level 1	Level 2	Level 3
	(In thousands)			
Assets:				
Available-for-sale investments	$ 377	$ 377	$	$
Derivatives	43,173	21,749	20,788	636
Total assets	$ 43,550	$ 22,126	$ 20,788	$ 636
Liabilities:				
Derivatives	$ 62,527	$	$ 62,941	$ (414)

The Company s contracts with certain of its counterparties allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. For classification purposes, the Company records the net fair value of all the positions with these counterparties as a net asset or liability. Each level in the table above displays the underlying contracts according to their classification in the accompanying consolidated balance sheet, based on this counterparty netting.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the change in the fair values of financial instruments categorized as level 3.

	Year Ended December 31, 2008 (In thousands)
Beginning balance	$ 3,256
Gains (losses), realized or unrealized	
Recognized in earnings	18,967
Recognized in other comprehensive income	(1,382)
Settlements, purchases and issuances	(19,791)
Ending balance	$ 1,050

Net unrealized losses during the twelve months ended December 31, 2008 related to level 3 financial instruments held on December 31, 2008 were $2.3 million.

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:

	2008	2007
	(In thousands)	
Balance at January 1 (including current portion)	$ 224,521	$ 216,641
Accretion expense	19,613	18,585
Reductions resulting from property disposals		(6,897)
Adjustments to the liability from changes in estimates	18,939	(945)

Liabilities settled	(4,222)	(2,863)
Balance at December 31	$ 258,851	$ 224,521
Current portion included in accrued expenses	(3,482)	(4,530)
Noncurrent liability	$ 255,369	$ 219,991

As of December 31, 2008, the Company had $148.8 million in surety bonds outstanding and $334.6 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 2008	2007	2006
	(In thousands)		
Self-insured occupational disease benefits:			
Service cost	$ 481	$ 1,310	$ 1,014
Interest cost	449	998	959
Net amortization	(3,882)	(1,688)	(1,952)
Total occupational disease	(2,952)	620	21
Traumatic injury claims and assessments	10,277	10,055	8,552
Total workers compensation expense	$ 7,325	$ 10,675	$ 8,573

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 2008	2007
	(In thousands)	
Beginning of year obligation	$ 17,463	$ 19,035
Service cost	481	1,310
Interest cost	449	998
Actuarial gain	(10,436)	(3,558)
Benefit and administrative payments	(544)	(322)
Net obligation at end of year	$ 7,413	$ 17,463

At December 31, 2008 and 2007, accumulated gains of $15.7 million and $9.1 million, respectively, were not yet recognized in occupational disease cost and were recorded in accumulated other comprehensive income. The expected accumulated gain that will be amortized from accumulated other comprehensive income into occupational disease cost in 2009 is $3.1 million.

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

	Year Ended December 31		
	2008	**2007**	**2006**
Weighted average assumptions:			
Discount rate	6.65%	6.50%	5.90%
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 2008	2007
	(In thousands)	
Occupational disease costs	$ 7,413	$ 17,463
Traumatic and other workers compensation claims	29,658	30,581
Total obligations	37,071	48,044
Less amount included in accrued expenses	6,964	6,973
Noncurrent obligations	$ 30,107	$ 41,071

As of December 31, 2008, the Company had $60.4 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 provides 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 or more than the maximum amount that can be deducted for U.S. federal income tax purposes.

A plan settlement occurred in 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, net and the remainder in cost of coal sales in the accompanying consolidated statements of income.

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.

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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	
	2008	2007	2008	2007
	(In thousands)			
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligations at January 1	$ 234,628	$ 231,234	$ 61,942	$ 53,242
Service cost	12,917	12,791	2,937	2,796
Interest cost	14,636	13,197	3,716	3,050
Plan amendments	1,907			8,787
Benefits paid	(13,344)	(13,281)	(2,540)	(2,776)
Other-primarily actuarial gain	(10,166)	(9,313)	(5,219)	(3,157)
Benefit obligations at December 31	$ 240,578	$ 234,628	$ 60,836	$ 61,942
CHANGE IN PLAN ASSETS				
Value of plan assets at January 1	$ 232,868	$ 216,061	$	$
Actual return on plan assets	(55,837)	27,382		
Employer contributions	2,617	2,706	2,540	2,776
Benefits paid	(13,344)	(13,281)	(2,540)	(2,776)
Value of plan assets at December 31	$ 166,304	$ 232,868	$	$
Accrued benefit cost	$ (74,274)	$ (1,760)	$ (60,836)	$ (61,942)
ITEMS NOT YET RECOGNIZED AS A COMPONENT OF NET PERIODIC BENEFIT COST				
Prior service cost	$ (2,352)	$ (232)	$ (18,616)	$ (22,074)
Accumulated gain (loss)	(63,780)	(3,390)	16,836	15,261
	$ (66,132)	$ (3,622)	$ (1,780)	$ (6,813)
BALANCE SHEET AMOUNTS				
Noncurrent asset	$	$ 7,307	$	$
Current liability	$ (788)	$ (538)	$ (2,673)	$ (2,761)
Noncurrent liability	$ (73,486)	$ (8,529)	$ (58,163)	$ (59,181)
	$ (74,274)	$ (1,760)	$ (60,836)	$ (61,942)

Pension Benefits

The accumulated benefit obligation for all pension plans was $228.5 million and $223.3 million at December 31, 2008 and 2007, 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 $9.4 million and $8.4 million, respectively, at December 31, 2008.

The prior service cost and net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2009 are $0.2 million and $2.8 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 2009 are $3.8 million and $(3.4) million, respectively.

The postretirement plan amendment in 2007 relates to the enhancement of benefits to employees discussed above.

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,	2008	2007	2006	2008	2007	2006
			(In thousands)			
Service cost	$ 12,917	$ 12,791	$ 9,676	$ 2,937	$ 2,796	$ 4,673
Interest cost	14,636	13,197	12,806	3,716	3,050	3,609
Expected return on plan assets*	(17,932)	(17,324)	(16,256)			
Amortization of prior service cost (credit)	(213)	(269)	(294)	3,458	1,663	1,547
Amortization of other actuarial losses (gains)	3,213	7,198	7,305	(3,644)	(3,014)	626
Settlements			3,150			
Net benefit cost	$ 12,621	$ 15,593	$ 16,387	$ 6,467	$ 4,495	$ 10,455

* The Company does not fund its other postretirement benefit liabilities.

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

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	
	2008	2007	2008	2007
Weighted average assumptions:				
Discount rate	6.85%	6.50%	6.85%	6.50%
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		
	2008	2007	2006	2008	2007	2006
Weighted average assumptions:						
Discount rate	6.50%	5.90%	5.80%/6.40%	6.50%	5.90%	5.80%
Rate of compensation increase	3.39%	3.39%	3.50%	N/A	N/A	N/A
Expected return on plan assets	8.50%	8.50%	8.25%	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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

modern portfolio theory modeling techniques in the development of its return assumptions. This technique projects rates of returns that can be generated through various asset allocations that lie within the risk tolerance set forth by members of the Company s pension committee (the Pension Committee). The risk assessment provides a link between a pension s risk capacity, management s willingness to accept investment risk and the asset allocation process, which ultimately leads to the return generated by the invested assets.

The health care cost trend rate assumed for 2009 is 11% and is expected to reach an ultimate trend rate of 5% by 2014. A one-percentage-point increase in the health care cost trend rate would have increased the postretirement benefit obligation at December 31, 2008 by $1.5 million. A one-percentage-point decrease in the health care cost trend rate would have decreased the postretirement benefit obligation at December 31, 2008 by $1.2 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	
	2008	2007
Equity securities	64%	73%
Debt securities	34%	23%
Cash and equivalents	2%	4%
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. In order to achieve a desired funded status, the Company expects to make contributions of $25.9 million to the pension plans in 2009. This estimate is based on current funding regulations, which are currently under review for potential modification to provide funding relief to companies that sponsor pension plans.

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

	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2009	$ 18,197	$ 3,864

2010	19,931	4,343
2011	21,116	4,511
2012	22,434	4,785
2013	24,498	5,077
Years 2014-2018	132,414	30,239
	$ 238,590	$ 52,819

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 United Mine Workers of America (UMWA) through premiums to be paid by assigned operators (former employers), transfers in 1993 and 1994 from an overfunded pension trust established for the benefit of retired UMWA members, and transfers from the Abandoned Mine Lands Fund (funded by a federal tax on coal production) commencing in 1995. The Company 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 provide for their future retirement needs. The Company s expense, representing its contributions to the plans, was $16.7 million, $14.5 million and $13.4 million for the years ended December 31, 2008, 2007 and 2006, 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.

Preferred Stock

In January, 2008, 84,376 shares of the Company s 5% Perpetual Cumulative Convertible Preferred Stock (Preferred Stock) were converted into 404,735 shares of the Company s common stock. On February 1, 2008, the Company redeemed the remaining 505 shares of Preferred Stock at the redemption price of $50.00 per share. During 2007 and 2006, 58,890 and 6,737 shares, respectively, of preferred stock were converted to common stock.

Stock Repurchase Plan

In September 2006, the Company s Board of Directors authorized a share repurchase program, for the purchase of up to 14,000,000 shares of the Company s common stock. At December 31, 2008, 10,925,800 shares of common stock were available for repurchase under the plan. During 2008, the Company repurchased 1,511,800 shares of its common stock under the repurchase program at an average cost of $35.62 per share. 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, 168,400 treasury shares that were purchased prior to the current program were contributed to the pension plans. There were no purchases made under the plan during 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Under the Company s Stock Incentive Plan (the Incentive Plan), 18,000,000 shares of the Company s common stock are reserved 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, 2008, the Company had stock options, restricted stock and restricted stock units 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, 2008:

	Common Shares (In thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In thousands)	Average Contract Life
Options outstanding at January 1	2,646	$ 18.20		
Granted	855	52.91		
Exercised	(521)	12.13		
Canceled	(47)	36.24		
Options outstanding at December 31	2,933	29.10	$ 10,216	6.35

Options exercisable at December 31	1,525	14.41	10,215	4.13

The aggregate intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 was $24.7 million, $14.9 million and $21.2 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Information regarding changes in stock options outstanding and not yet vested and the related grant-date fair value under the Incentive Plan follows for the year ended December 31, 2008:

	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value
Unvested options at January 1	915	$ 14.07
Granted	855	21.29
Vested	(315)	13.84
Canceled	(47)	15.57
Unvested options at December 31	1,408	18.42

Compensation cost of stock option grants is recognized straight-line over the options vesting periods. Compensation expense related to stock options for the years ended December 31, 2008, 2007 and 2006 was $10.7 million, $3.8 million and $1.5 million, respectively. As of December 31, 2008, there was $14.1 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, 2008, 2007 and 2006 was $4.4 million, $0.3 million and $4.0 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 implied volatility from traded options on the Company s stock. The expected life of the option was determined based on historical exercise activity. Substantially all stock options granted vest ratably over three years. The options provide for the continuation of vesting for retirement-eligible recipients that meet certain criteria. The expense for these options is recognized through the date that the employee first becomes eligible to retire and is no longer required to provide service to earn part or all of the award. 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.

Weighted average assumptions regarding granted options follow:

	Year Ended December 31		
	2008	2007	2006
Weighted average grant-date fair value per share of options granted	$ 21.29	$ 14.37	$ 13.53
Assumptions (weighted average):			
Risk-free interest rate	2.86%	4.70%	4.75%
Expected dividend yield	0.6%	0.7%	0.7%
Expected volatility	45.7%	39.5%	40.7%
Expected life (in years)	4.7	6.0	5.0

Restricted Stock and Restricted Stock Unit Awards

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Information regarding restricted stock and restricted stock unit activity and weighted average grant-date fair value follows for the year ended December 31, 2008:

	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	112	$ 27.95	139	$ 16.41
Granted	24	49.05	54	52.69
Vested	(40)	23.92	(128)	14.67
Canceled	(5)	49.47	(1)	37.77
Outstanding at December 31	91	34.15	64	50.47

The weighted average fair value of restricted stock granted during 2007 and 2006 was $33.27 and $36.73, respectively. The weighted average fair value of restricted stock units granted during 2006 was $37.77; there were none granted during 2007. The total grant-date fair value of restricted stock that vested during 2008, 2007 and 2006 was $1.0 million, $0.1 million and $0.3 million, respectively. The total grant-date fair value of restricted stock units that vested during 2008, 2007 and 2006 was $1.9 million, $2.0 million and $1.7 million, respectively. Unearned compensation of $3.8 million will be recognized over the remaining vesting period of the outstanding restricted stock and restricted stock units. The Company recognized expense of approximately $1.9 million, $1.8 million and $2.0 million related to restricted stock and restricted stock units for the years ended December 31, 2008, 2007 and 2006, 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 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, 2008, certain of the stock price and EBITDA performance measurements were satisfied under the plan, and the Company issued 0.2 million shares of common stock and paid cash of $3.5 million under the awards. The Company recognized $1.1 million, $1.4 million and $7.9 million of expense under this award in the years ended December 31, 2008, 2007 and 2006, respectively. The expense is included in selling, general and administrative expenses 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 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 of $21.8 million and $21.5 million at December 31, 2008 and 2007, 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

participants are general creditors of the company as to their deferred compensation in the plans. During 2008, the Company contributed $13.8 million to the plan.

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, based upon the fair market value of the underlying investment on that date. The amount the employee will receive from the plan 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 that date. The liability under the plan was $19.0 million at December 31, 2008 and $30.7 million at December 31, 2007.

The Company s net (income) expense related to the deferred compensation plan for the years ended December 31, 2008, 2007 and 2006 was $2.3 million, $5.3 million and $(2.8) million, 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 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 $486.1 million, $196.7 million and $162.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008 and 2007, accounts receivable from electric utilities located in the United States totaled $160.0 million and $171.8 million, respectively, or 74% and 75% of total trade receivables, 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 139.6 million tons of coal in 2008. Approximately 76% of this tonnage (representing approximately 66% 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 $7.07 to $180.00 per ton. Long-term contracts ranged in remaining life from one to nine years. Sales (including spot sales) to our largest customer, Tennessee Valley Authority, were $416.5 million, $336.4 million and $317.8 million for the years ended December 31, 2008, 2007 and 2006, 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

	Year Ended December 31		
	2008	2007	2006
	(In thousands)		
Basic weighted average shares outstanding	143,604	142,518	142,770
Effect of common stock equivalents under Incentive Plan	779	1,068	1,342
Effect of common stock equivalents arising from Preferred Stock	33	433	700
Diluted weighted average shares outstanding	144,416	144,019	144,812

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. In addition, the Company enters into various non-cancelable royalty lease agreements under which future minimum payments are due.

Minimum payments due in future years under these agreements in effect at December 31, 2008 are as follows:

	Operating Leases	Royalties
	(In thousands)	
2009	$ 33,806	$ 23,254
2010	32,331	23,316
2011	28,452	22,655
2012	23,173	6,905
2013	20,338	7,272
Thereafter	38,265	22,956
	$ 176,365	$ 106,358

Rental expense, including amounts related to these operating leases and other shorter-term arrangements, amounted to $42.8 million in 2008, $37.2 million in 2007 and $28.8 million in 2006. Royalty expense, including production royalties, was $259.2 million in 2008, $204.7 million in 2007 and $201.1 million in 2006.

As of December 31, 2008, certain of the Company s lease obligations were secured by outstanding surety bonds totaling $52.0 million.

20. Guarantees

On December 31, 2005, the Company entered into the Purchase Agreement with Magnum. Pursuant to the Purchase Agreement, the Company sold the stock of three of its subsidiaries and their Central Appalachian mining operations. 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. 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, the Company had approximately $92.0 million of surety bonds related to properties sold to Magnum. Patriot Coal Corporation acquired Magnum in July 2008, and, as a result, Magnum will be required to post letters of credit in the Company s favor for the full amount of the reclamation obligation on or before February 2011.

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 were assigned to Magnum, but the Company has guaranteed 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 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, 2008, the cost of purchasing 14.1 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 $200.7 million, and the cost of purchasing 3.7 million tons of coal to supply the assigned and guaranteed contracts over their duration would exceed the sales price under the contracts by approximately $104.7 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 $6.1 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 consolidated financial statements as of December 31, 2008. 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 $51.8 million at December 31, 2008, which is not recorded as a liability in the Company s consolidated 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. Business Interruption Insurance Recoveries

The idling of the Company s West Elk mine in Colorado during the first quarter of 2006 as a result of a combustion-related event in October, 2005 cost the Company an estimated $30.0 million in lost profits. The Company recorded insurance recoveries related to the event of $41.9 million, of which $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.

22. 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

will not have a material adverse effect on the consolidated financial condition, results of operations or liquidity of the Company.

23. 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, 2008, 2007 and 2006 are presented below. Results for the operating segments include all direct costs of mining. Corporate, Other and Eliminations includes the change in fair value of coal derivatives and coal trading activities, net; corporate overhead; land management; other support functions; and the elimination of intercompany transactions.

	PRB	WBIT	CAPP	Corporate, Other and Eliminations	Consolidated
			(In thousands)		
December 31, 2008					
Coal sales	$ 1,162,056	$ 659,389	$ 1,162,361	$	$ 2,983,806
Income (loss) from operations	109,032	121,261	296,699	(66,603)	460,389
Total assets	1,845,685	2,079,689	1,079,341	(1,025,751)	3,978,964
Depreciation, depletion and amortization	117,753	81,174	92,189	1,732	292,848
Capital expenditures	123,909	162,698	81,860	128,880	497,347
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
	111,350	46,530	48,789	1,685	208,354

Depreciation, depletion and amortization					
Capital expenditures	121,736	138,631	231,311	131,509	623,187

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31 2008	2007	2006
	(In thousands)		
Income from operations	$ 460,389	$ 229,617	$ 336,667
Interest expense	(76,139)	(74,865)	(64,364)
Interest income	11,854	2,600	3,725
Other non-operating expense		(2,273)	(7,447)
Income before income taxes	$ 396,104	$ 155,079	$ 268,581

24. Quarterly Financial Information (Unaudited)

Quarterly financial data for the years ended December 31, 2008 and 2007 is summarized below:

	March 31	June 30	September 30	December 31 (b)
	(In thousands, except per share data)			
2008:				
Coal sales	$ 699,350	$ 785,117	$ 769,458	$ 729,881
Gross profit	111,904	144,681	129,901	120,550
Income from operations	116,450	168,950	87,751	87,238
Net income	81,147	112,997	97,848	62,338
Basic earnings per common share	0.57	0.78	0.68	0.44
Diluted earnings per common share	0.56	0.78	0.68	0.44

	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(e)	0.20	0.26	0.19	0.57
Diluted earnings per common share(e)	0.20	0.26	0.19	0.56

(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) The Company filed for black lung excise tax refunds and recognized a refund of $11.0 million, plus interest of $10.3 million, in the fourth quarter of 2008.

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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, 2008					
Reserves deducted from asset accounts:					
Other assets other notes and accounts receivable	$ 216	$ 42	$	$ 33	$ 225
Current assets supplies and inventory	13,500	1,548		2,288	12,760
Deferred income taxes	69,326	(57,973)	(3,899)(d)	7,059	395
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

(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 that was recorded as paid-in capital.

(d) Relates to the reversal of tax benefits from the exercise of employee stock options that was recorded as paid-in capital.

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Signatures

Pursuant to the requirements of Section 13 or 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 27, 2009

Signatures	Capacity	Date
Steven F. Leer	Chairman and Chief Executive Officer (Principal Executive Officer)	February 27, 2009
John T. Drexler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2009
John W. Lorson	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2009
* James R. Boyd	Director	February 27, 2009
* Frank M. Burke	Director	February 27, 2009
* John W. Eaves	President, Chief Operating Officer and Director	February 27, 2009
* Patricia F. Godley	Director	February 27, 2009
* Douglas H. Hunt	Director	February 27, 2009
*	Director	February 27, 2009

Brian J. Jennings		
*	Director	February 27, 2009
Thomas A. Lockhart		
*	Director	February 27, 2009
A. Michael Perry		
*	Director	February 27, 2009
Robert G. Potter		

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Signatures	Capacity	Date
*	Director	February 27, 2009
Theodore D. Sands		
*	Director	February 27, 2009
Wesley M. Taylor		

*By:

Robert G. Jones,
Attorney-in-fact

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 to 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 to 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 to 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 to the registrant s Quarterly Report on Form 10-Q for the period ended September 30, 2007).
2.5	Agreement, dated as of March 27, 2008, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant s Quarterly Report on Form 10-Q for the period ended March 31, 2008).
2.6	Amendment No. 1 to Agreement, dated as of February 5, 2009, by and between Arch Coal, Inc. and Magnum Coal Company
3.1	Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated herein by reference to Exhibit 3.1 to the registrant s Current Report on Form 8-K filed on May 5, 2006).
3.2	Arch Coal, Inc. Bylaws, as amended effective as of December 5, 2008 (incorporated herein by reference to Exhibit 3.1 to the registrant s Current Report on Form 8-K filed on December 10, 2008).
4.1	Form of Rights Agreement, dated March 3, 2000 (incorporated herein by reference to Exhibit 1 to the registrant s Current Report on Form 8-A filed on March 9, 2000).
4.2	Indenture, dated as of June 25, 2003, by and among Arch Western Finance, LLC, Arch Coal, Inc., Arch Western Resources, LLC, Arch of Wyoming, LLC, Mountain Coal Company, L.L.C., Thunder Basin Coal Company, L.L.C. and The Bank of New York, as trustee (incorporated herein by reference to Exhibit 4.1 to the Registration Statement on Form S-4 (Reg. No. 333-107569) filed by Arch Western Finance, LLC on August 1, 2003).
4.3	First Supplemental Indenture dated October 22, 2004 among Arch Western Finance, LLC, Arch Western Resources, LLC, Arch of Wyoming, LLC, Arch Western Bituminous Group, LLC, Mountain Coal Company, L.L.C., Thunder Basin Coal Company, L.L.C., Triton Coal Company, LLC, and The Bank of New York, as trustee (incorporated herein by reference to Exhibit 4.4 to the Current Report on Form 8-K filed by the registrant on October 28, 2004).
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 herein 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 to 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).

Exhibit	Description
10.5*	Form of Employment Agreement for Executive Officers of Arch Coal, Inc. (other than Steven F. Leer) (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by the registrant on November 16, 2006).
10.6	Coal Lease Agreement dated as of March 31, 1992, among Allegheny Land Company, as lessee, and UAC and Phoenix Coal Corporation, as lessors, and related guarantee (incorporated herein by reference to the Current Report on Form 8-K filed by Ashland Coal, Inc. on April 6, 1992).
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 to 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 to 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 to 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 to 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 to 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 to 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 to 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 to 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).

Exhibit	Description
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).
10.21	State Coal Lease executed January 18, 2008 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company, as lessee, for lands located in Emery County, Utah
10.22	Form of Indemnity Agreement between Arch Coal, Inc. and Indemnitee (as defined therein) (incorporated herein by reference to Exhibit 10.15 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.23*	Arch Coal, Inc. Incentive Compensation Plan For Executive Officers (incorporated herein by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by the registrant on February 28, 2005).
10.24*	Arch Coal, Inc. Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.3 to the registrant s Current Report on Form 8-K filed on December 11, 2008).
10.25*	Arch Coal, Inc. 1997 Stock Incentive Plan (as amended and restated on December 5, 2008) (incorporated herein by reference to Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on December 11, 2008).
10.26*	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).
10.27*	Arch Coal, Inc. Outside Directors Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.4 of the registrant s Current Report on Form 8-K filed on December 11, 2008).
10.28*	Second Amendment to the Arch Mineral Corporation Supplemental Retirement Plan effective January 1, 1998 (incorporated herein by reference to Exhibit 10.31 to the registrant s Annual Report on Form 10-K for the year ended December 31, 1998).
10.29*	Arch Coal, Inc. Supplemental Retirement Plan (as amended on December 5, 2008) (incorporated herein by reference to Exhibit 10.2 to the registrant s Current Report on Form 8-K filed on December 11, 2008)
10.30	Receivables Purchase Agreement, dated as of February 3, 2006, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, as issuer, the financial institutions from time to time party thereto, as LC Participants, and PNC Bank, National Association, as Administrator on behalf of the Purchasers and as LC Bank (incorporated herein by reference to Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on February 14, 2006).
10.31	First Amendment to Receivables Purchase Agreement, dated as of April 24, 2006, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, the financial institutions from time to time party thereto, as LC Participants, and PNC Bank, National Association, as Administrator on behalf of the Purchasers and as LC Bank (incorporated herein by reference to Exhibit 10.2 to the registrant s Quarterly Report on Form 10-Q for the period ended March 31, 2006).
10.32	Second Amendment to Receivables Purchase Agreement, dated as of June 23, 2006, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, the various financial institutions party thereto and PNC Bank, National Association, as administrator and as LC Bank (incorporated by reference to Exhibit 10.2 to the registrant s Current Report on Form 8-K filed on June 27, 2006).
10.33	Third Amendment to Receivables Purchase Agreement, dated as of May 22, 2008, 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 herein by reference to Exhibit 10.1 to the registrant s Current Report on Form 8-K

	filed on May 23, 2008).
10.34*	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).
10.35*	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).

Exhibit	Description
10.36*	Form of Non-Qualified Stock Option Agreement (for stock options granted prior to February 21, 2008) (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).
10.37*	Form of 2008 Restricted Stock Unit Contract for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.3 to the registrant s Current Report on Form 8-K filed on February 27, 2008).
10.38*	Form of 2008 Non-Qualified Stock Option Agreement for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.4 to the registrant s Current Report on Form 8-K filed on February 27, 2008).
10.39*	Form of Non-Qualified Stock Option Agreement (for stock options granted on or after February 21, 2008) (incorporated herein by reference to Exhibit 10.5 to the registrant s Current Report on Form 8-K filed on February 27, 2008).
10.40*	Form of Performance Unit Contract (incorporated herein by reference to Exhibit 10.2 to the registrant s Current Report on Form 8-K filed on February 23, 2009).
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.
23.2	Consent of Weir International, Inc.
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 John T. Drexler
32.1	Section 1350 Certification of Steven F. Leer
32.2	Section 1350 Certification of John T. Drexler.

* Denotes management contract or compensatory plan arrangements.