ARCH COAL INC
Form 10-K
March 01, 2010

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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, 2009

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such filed). 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 Smaller reporting company o
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). 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, 2009 was approximately $2.2 billion.

On February 22, 2010, 162,474,101 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 22, 2010 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. 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;
- the deferral of contracted shipments of coal by 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;

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

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

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

These factors should not be construed as exhaustive and should be read in conjunction with the other cautionary statements included in this document. These risks and uncertainties, 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, 2009 (which includes fourth quarter sales only from the former Jacobs Ranch mine complex, which we acquired on October 1, 2009), we sold approximately 126.1 million tons of coal, including approximately 7.5 million tons of coal we purchased from third parties, fueling approximately 12.7% of all coal-based electricity generated in the United States. We sell substantially all of our coal to power plants, steel mills and industrial facilities. At December 31, 2009, we operated 19 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 on 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. We expect United States coal exports to increase in 2010, driven primarily by improving metallurgical coal demand. 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. On October 1, 2009, we acquired Rio Tinto s Jacobs Ranch mine complex in the Powder River Basin of Wyoming which included 345 million tons of low-cost, low-sulfur coal reserves and integrated it into the Black Thunder mine.

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Coal Characteristics

In general, end users characterize coal as steam coal or metallurgical coal. Heat value, sulfur, ash, moisture content, and volatility in the case of metallurgical coal, are 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-dioxide emission reduction technology.

All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 79.3% consist of compliance coal, while an additional 6.1% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Higher sulfur coal can be burned in plants equipped with sulfur-dioxide emission reduction technology, such as scrubbers, and in facilities that blend compliance and noncompliance coal.

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. The upheaval in the global financial markets experienced in late 2008 spread to the global energy markets, affecting energy demand throughout 2009. According to the Energy Information Administration (EIA), global energy markets continue to adjust to highly uncertain conditions precipitated by the commodity (oil and other energy fuels) price collapse in 2008. Even as energy demand faltered and the world debated the effects of reliance on all forms of fossil fuels, coal remained (and remains) a major contributor to global energy supplies because of its availability, stability and affordability.

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According to the International Energy Agency (IEA), coal provided approximately 41.5% of the world s electricity in 2007 and it is also used in producing approximately 70% 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, and as such its distribution network is varied and economical, creating viable energy supply alternatives for developed and developing nations alike.

Coal is traded worldwide and can be transported to demand centers by ship, rail, barge, and truck. Worldwide coal production approximated 6.3 billion tonnes in 2007 and 6.7 billion tonnes in 2008, according to the IEA. China remains the largest producer of coal in the world. It produced nearly 2.8 billion tonnes in 2008, according to the IEA, followed by the USA at approximately 1 billion tonnes and India at nearly 490 million tonnes. The National Bureau of Statistics of China reports that 2.7 billion tonnes of coal have been produced domestically through November of 2009. Historically, Australia has been the world s largest coal exporter, exporting more than 252 million tonnes in 2008, according to the World Coal Institute (WCI). Indonesia, Russia, Colombia, and South Africa have also historically been significant exporters. Indonesia in particular has seen substantial growth in its coal exports in the last few years; however, its growing domestic energy demand may result in a decrease in exports as it moves toward greater self-sufficiency. China too has reduced its level of total exports as domestic requirements became paramount and has become a large net importer.

International demand for coal continues to be driven by growth in electrical power generation capacity, most significantly in China and India going forward. China and India represented approximately 48% of total world coal consumption in 2006 and are expected to account for approximately 59% by 2030, according to the EIA. Increased international demand led to a substantial rise in the demand for coal exports from the United States during 2008 as the demand for coal for both power generation and steel production, coupled with supply issues around the globe, strained global coal supplies. The situation altered in 2009 as weakened global energy demand caused demand for U.S. export coal to decline. As global economic conditions improve and regions return to growth, we expect the demand for U.S. coal 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 or processing facilities. Coal consumption in the United States increased from 398.1 million tons in 1960 to approximately 1.0 billion tons in 2009, according to the EIA s Short Term Energy Outlook. Although full-year data for 2009 is not yet available, the global downturn affected U.S. coal consumption. In 2009, coal consumption in the U.S. was affected not only by lower total electricity generation but also by increases in generation from other electricity sources including natural gas and hydropower.

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	**2002**	**2009**	**2011**	**2020**	**2030**	**2009-2030**
	(Tons, in millions)					
Electric power	978	936	998	1,073	1,147	0.9%
Other industrial	61	47	51	53	52	0.5%
Coke plants	24	16	20	20	17	0.3%
Residential/commercial	4	3	3	3	3	0.4%
Coal-to-liquids				32	57	n/a

Total U.S. coal consumption	1,067	999.5	1,072	1,181	1,276	1.1%

Source: EIA Annual Energy Outlook 2010

EIA Short Term Energy Outlook (February 2010)

According to the EIA, coal accounted for approximately 45% of U.S. electricity generation in 2009, and based on projected 19% growth in electricity demand, coal consumption is projected to grow by more than 20% by 2030, reaching 1.2 billion tons. (These amounts assume no future federal or state carbon emissions legislation

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is enacted and do not take into account recent market conditions.) Historically, coal has been considerably less expensive than natural gas or oil.

We estimate that the cost of generating electricity from coal is significantly lower than the cost of generating electricity from other fossil fuels. According to the EIA, the average delivered cost of coal to electric power generators for 2009 was $2.21/mm Btus, which was $7.16/mmBtu less expensive than petroleum liquids and $2.40/mmBtu lower than natural gas. Coal is also competitive with existing nuclear power generation, 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 2009, renewable power generation (excluding hydro), such as wind power and biomass, accounted for only 4% of all electricity generated in the United States and is currently not a reliable source for baseload electric power. The following chart shows the breakdown of U.S. electricity generation by energy source for 2009, according to the EIA:

Source: EIA Short Term Energy Outlook (February 2010).

The EIA has projected that approximately 108 gigawatts of new electricity capacity (net of retirements) will be needed between 2008 and 2030, with approximately 14% of the new capacity estimated to come from coal fueled generation. 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, to integrated gasification combined cycle (IGCC) units, which permit coal to be turned into a gasified product for the easier capture of carbon dioxide in the future. Many projects that are moving forward are being developed by municipal and regulated utilities due to their ability to recover costs, in addition to their prior experience with coal.

The other major market for coal is the steel industry. Coal is essential for iron and steel production. According to the WCI, approximately 70% of all steel is produced from iron made in coal fired blast furnaces. The steel industry uses metallurgical coal, which is distinguishable from other types of coal by 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 during 2009 fell from their record highs of the previous year due to the effects of the worldwide economic recession. Historically, volatile oil and gas prices and global energy security concerns have increased 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-

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sulfur diesel fuel, gasoline and other oil products, such as plastics and solvents. Currently, there are only a limited number of projects moving forward because of lower oil and natural gas prices.

U.S. Coal Production. The United States is the second largest coal producer in the world, exceeded only by China. According to the EIA, there is over 200 billion tons of recoverable coal in the U.S. The U.S. Department of Energy estimates that current domestic recoverable coal reserves could supply enough electricity to satisfy domestic demand for approximately 200 years. Annual coal production in the United States has increased from 434 million tons in 1960 to approximately 1.0 billion tons in 2009 based on information provided by the Mine Safety and Health Administration.

Coal is mined from coal fields throughout 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 an estimated 629 million tons in 2009, as competitive mining costs and regulations limiting sulfur dioxide emissions have continued the 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 Colorado,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 an estimated 342 million tons in 2009 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%. Southern Appalachia primarily covers Alabama and generally has a heat content ranging from 11300 to 12300 Btu and a sulfur content ranging from 0.7% - 3.0%.

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 103.3 million tons in 2009. 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. Although down from the previous year, U.S. exports began to increase in the second half of 2009, supported by recovering global economies and continued growth in Chinese and Indian steel markets in

particular. This is a trend we expect to continue. Because of this, we believe that the United States will continue to be an increasingly important swing supplier of coal to the global marketplace in the near term.

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Historically, coal imported from abroad has represented a relatively small share of total U.S. coal consumption, and this remained the case in 2009. According to the EIA, coal imports increased from 8.9 million tons in 1994 to approximately 22.8 million tons in 2009, which represented a fall from the 34 million tons imported in 2008. The drop was primarily related to the decline in demand for power generation as well as weaker domestic coal prices. 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 import growth to be significant as more and more global coal will likely be directed to Asia.

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 below under Our Mining Operations General. In 2009, approximately 80% of the coal that we produced came from surface mining operations.

Surface mining involves removing the topsoil then drilling and 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.

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 Our

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Mining Operations General. In 2009, approximately 20% of the coal that we produced came from underground mining operations.

Our underground mines are typically operated using one or both of two different mining 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 2009, approximately 17% of the coal that we produced came from underground mining operations generally using longwall mining techniques.

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 2009, 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 2009, approximately 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 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 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 2009, our preparation plants processed approximately 80% to 90% 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, 2009, we operated 19 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

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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, 2009, 2008 and 2007 contained in Note 23 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). 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 and preparation plants at strategic locations in close proximity to 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:

The following table provides a summary of information regarding our active mining complexes at December 31, 2009, the total sales associated with these complexes for the years ended December 31, 2007, 2008 and 2009 and the total reserves associated with these complexes at December 31, 2009. 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

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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) 2007	2008	2009	Total Cost of Property, Plant and Equipment at December 31, 2009 ($ in millions)	Assigned Reserves (Million tons)
						(Million tons)			
Powder River Basin:									
Black Thunder	S		D, S	UP/BN	86.2	88.5	81.2	$ 996.6	1,521.6
Coal Creek	S		D, S	UP/BN	10.2	11.5	9.8	148.1	197.1
Western Bituminous:									
Arch of Wyoming	S		L	UP		0.2	0.1	23.8	14.8
Dugout Canyon	U		LW, CM	UP	4.0	4.3	3.2	137.0	19.8
Skyline	U		LW, CM	UP	2.4	3.3	2.8	160.1	19.2
Sufco	U		LW, CM	UP	6.7	7.4	6.6	210.4	66.2
West Elk	U		LW, CM	UP	6.2	5.3	4.0	432.2	74.9
Central Appalachia:									
Coal-Mac	S	U	L, E	NS/CSX	3.9	3.7	2.9	169.3	26.7
Cumberland River	S(1), U(2)	U	L, CM, HW	NS	2.4	2.4	1.6	130.2	22.7
Lone Mountain	U(3)		CM	NS/CSX	2.4	2.7	2.2	185.7	30.6
Mountain Laurel	U	S(2)	L, LW, CM	CSX	1.0	4.3	4.4	437.1	86.4
Totals					125.4	133.6	118.8	$ 3,030.5	2,080

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, 2009. 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. The amount of coal that we purchased from third parties and processed through our loadout facilities was negligible in 2008 and 2009. 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 7.3 million tons in 2009, 6.0 million tons in 2008 and 8.4 million tons in 2007.

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.

Powder River Basin

Black Thunder. Black Thunder is a surface mining complex located on approximately 33,800 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 81.2 million tons of coal in 2009.

We control a significant portion of the coal reserves through federal and state leases. The Black Thunder mining complex had approximately 1.5 billion tons of proven and probable reserves at December 31, 2009. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of 190.0 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

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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 seven active pit areas and three 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 9.8 million tons of coal in 2009.

We control a significant portion of the coal reserves through federal and state leases. The Coal Creek mining complex had approximately 197 million tons of proven and probable reserves at December 31, 2009. 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 tract of coal adjacent to the Coal Creek mining complex has been nominated for lease, and other potential 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. 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 0.1 million tons of coal in 2009.

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 14.8 million tons of proven and probable reserves at December 31, 2009. 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 has extracted steam coal from the Rock Canyon and Gilson seams. The Dugout Canyon mining complex shipped 3.2 million tons of coal in 2009.

We control a significant portion of the coal reserves through federal and state leases. The Dugout Canyon mining complex had approximately 19.8 million tons of proven and probable reserves at December 31, 2009. The coal seam

currently being mined will sustain current production levels until approximately mid-2012, at which point we will need to transition to another coal seam to continue mining.

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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 2.8 million tons of coal in 2009.

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 19.2 million tons of proven and probable reserves at December 31, 2009. The reserve area currently being mined will sustain current production levels through 2011, at which point we will need to transition to a new reserve area in order to continue mining.

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 27,550 acres in Sevier County, Utah. The Sufco mining complex extracts steam coal from the Upper Hiawatha seam. The Sufco mining complex shipped 6.6 million tons of coal in 2009.

We control a significant portion of the coal reserves through federal and state leases. The Sufco mining complex had approximately 66.2 million tons of proven and probable reserves at December 31, 2009. The coal seam currently being mined will sustain current production levels through 2020, at which point we will need to transition to a new coal seam in order to continue mining.

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. The West Elk mining complex shipped 4.0 million tons of coal in 2009.

We control a significant portion of the coal reserves through federal and state leases. The West Elk mining complex had approximately 74.9 million tons of proven and probable reserves at December 31, 2009. Without the addition of more coal reserves, the current reserves will sustain current production levels through 2019 before annual output starts to significantly decline.

The West Elk complex currently consists of a longwall, two continuous miner sections and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad. In 2009, we processed a small portion of the coal mined at this complex at a nearby preparation plant. In 2010, a new coal preparation plant with supporting coal handling facilities will be constructed to process coal at the West Elk mine site. The loadout facility can load an 11,000-ton train in less than three hours.

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 primarily 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 2.9 million tons of coal in 2009.

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We control a significant portion of the coal reserves through private leases. The Coal-Mac mining complex had approximately 26.7 million tons of proven and probable reserves at December 31, 2009. 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 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 all 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 about 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 1.6 million tons of coal in 2009.

We control a significant portion of the coal reserves through private leases. The Cumberland River mining complex had approximately 22.7 million tons of proven and probable reserves at December 31, 2009. 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 (two captive, two contract) operating four continuous miner sections, two captive surface operations, one captive highwall miner, 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 2.2 million tons of coal in 2009.

We control a significant portion of the coal reserves through private leases. The Lone Mountain mining complex had approximately 30.6 million tons of proven and probable reserves at December 31, 2009. Without the addition of more coal reserves, the current reserves will sustain current production levels until 2020 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 38,280 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 4.4 million tons of coal in 2009.

We control a significant portion of the coal reserves through private leases. The Mountain Laurel mining complex had approximately 86.4 million tons of proven and probable reserves at December 31, 2009. Without

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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, two contract surface operations, 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 and hydropower. 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 primary 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 and a Western Bituminous mine. 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 function 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 2009, we sold coal to domestic customers located in 39 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, 2009, we derived approximately 23% of our total coal revenues from sales to our three largest customers Tennessee Valley Authority, Ameren Corporation and Pacificorp and approximately 48% of our total coal revenues from sales to our 10 largest customers. During 2009, we also exported coal to customers located throughout countries in North America, Europe, South America, and Asia. Coal sales revenue from foreign customers approximated $194.4 million for 2009, $486.1 million for 2008 and $196.7 million for 2007. We do not have foreign currency exposure for our international sales as all sales are denominated and settled in U.S. dollars.

Beginning in the third quarter of 2008, worldwide steel prices plummeted and steel production on a global basis was significantly curtailed. In particular, steel demand collapsed in the United States, Western Europe and Eastern Europe. These are the principal geographic regions where our metallurgical products are sold. As a result, we produced a smaller percentage of metallurgical quality coal during 2009 than we did in 2008. We sold approximately 2.1 million tons of metallurgical quality coal in 2009, 4.4 million tons of metallurgical quality coal in 2008 and approximately 2.1 million tons of metallurgical quality coal in 2007.

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

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contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2009, we sold approximately 72% of our coal under long-term supply arrangements. The majority 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, 2009, the average volume-weighted remaining term of our long-term contracts was approximately 3.1 years, with remaining terms ranging from one to eight years. At December 31, 2009, we had a sales backlog, including a backlog subject to price re-opener or extension provisions, of approximately 357.5 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 negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re-opener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, *force majeure*, termination, damages 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 or the customer consumption requirements. 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 purchase or 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 equivalent delivered cost.

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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 volumes and/or prices associated with our 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 for more information about the market risks associated with these strategies at December 31, 2009.

Transportation. We ship our coal to domestic customers by means of railroad, barges, vessels 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, barge or vessel.

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, a partnership that 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 or by truck delivery. 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.

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Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality, delivered costs to the customer and reliability of supply. Our principal domestic competitors include Alpha Natural Resources, Inc., CONSOL Energy Inc., Massey Energy Company, Patriot Coal Corporation, Peabody Energy Corp. and Cloud Peak Energy. 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 natural gas, nuclear energy, 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.

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 explosives and fuel, and preferred suppliers for other parts at our business such as dragline and shovel parts and related services. 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.

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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.

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.

On December 12, 2008, OSM finalized a rulemaking regarding the interpretation of the stream buffer zone provisions of SMCRA which confirmed that excess spoil from mining and refuse from coal preparation could be placed in permitted areas of a mine site that constitute waters of the United States. On November 30, 2009, OSM announced another rulemaking that would reinterpret the regulations finalized eleven months earlier. We cannot predict how the regulations may change or how they may affect coal production.

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 2009, we recorded $32.7 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, 2009, we have self-bonded an aggregate of approximately $352.0 million and have posted an aggregate of approximately $297.3 million in surety bonds for reclamation purposes. In addition, we had approximately $153.5 million of surety bonds and letters of credit outstanding at December 31, 2009 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;

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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 2009, we recorded $64.9 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 is likely, such as EPA s proposal published on December 8, 2009 to revise the national ambient air quality standard for oxides of sulfur and a similar proposal announced on January 6, 2010 for ozone. Regulation of additional emissions such as carbon dioxide or other greenhouse gases as proposed or determined by EPA on October 27, October 30 and December 15, 2009 may eventually be applied to stationary sources such as coal-fueled power plants and industrial boilers (see discussion of Climate Change, below). This application 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

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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.

In addition, EPA announced on January 6, 2010 a proposal to adopt a new, more stringent primary ambient air quality standard for ozone and to change the way in which the secondary standard is calculated. Should these 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 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 which the agency predicts will take approximately two years.

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.

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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. On December 24, 2009, the EPA announced that it had recommended to the Office of Management and Budget an Information Collection Request that would require all US power plants with coal or oil-fired generating units to submit emissions information. With this information the EPA intends to propose standards for all air toxic emissions, including mercury, for coal and oil-fired units by March 10, 2011. The EPA hopes to make these new standards final by November 16, 2011. 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. On December 15, 2009, EPA published a formal determination that six greenhouse gases, including carbon dioxide and methane, endanger both the public health and welfare of current and future generations. In the same Federal Register rulemaking, EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. 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,

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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. On October 27, 2009, the EPA announced how it will establish thresholds for phasing-in and regulating greenhouse gas emissions under various provisions of the Clean Air Act. Three days later, on October 30, 2009, the EPA published a final rule in the Federal Register that requires the reporting of greenhouse gas emissions from all sectors of the American economy, although reporting of emissions from underground coal mines and coal suppliers as originally proposed has been deferred pending further review. 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. These 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 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-

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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.

Notwithstanding the additional environmental protections designed in the 2007 NWP 21, on July 15, 2009, the Corps proposed to immediately suspend the use of the NWP 21 in six Appalachian states, including West Virginia, Kentucky and Virginia where the Company conducts operations. In addition, in the same notice, the Corps proposed to modify the NWP 21 following the receipt and review of public comments to prohibit its further use in the same states during the remaining term of the permit which is March 12, 2012. The Corps is now reviewing the more than 21,000 public comments it has received. The agency has not announced when it is expected to complete its review and reach a final decision.

Regardless of the outcome of the Corps decision about any continuing use of NWP 21, it does not prevent the Company s operations from seeking an individual permit under § 404 of the CWA, nor does it restrict an operation from utilizing another version of the nationwide permit authorized for small underground coal mines that must construct fills as part of their mining operations.

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 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.

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Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, which we refer to as CERCLA, and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could 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 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 11, 2010, we employed a total of approximately 4,601 persons, approximately 152 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 22, 2010 and their positions and offices during the last five years:

Name	Age	Position
C. Henry Besten, Jr.	61	Mr. Besten has served as our Senior Vice President-Strategic Development since 2002.
John T. Drexler	40	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	52	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. and CoaLogix.
Sheila B. Feldman	55	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.
Robert G. Jones	53	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	49	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	57	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 Business Roundtable, the BRT, the University of the Pacific and Washington University 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	55	Mr. Peugh has served as our Vice President-Business Development since 1995.
Deck S. Slone	46	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	54	

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.

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

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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 biomass 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.

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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.

Certain of our customers have deferred, and other customers may in the future seek to defer, contracted shipments of coal, which could affect our results of operations and liquidity.

As the ongoing global economic recession has caused the price of, and demand for, coal to decline, certain of our thermal and metallurgical coal customers have delayed shipments, or requested deferrals, pursuant to our existing long-term coal supply agreements. Other customers similarly may seek to delay shipments or request deferrals under existing agreements. In the current economic environment, the spot market for coal may not provide an acceptable alternative to sell our uncommitted tons. We currently are evaluating customer deferrals and are in negotiations with a number of the customers that have made such requests. There is no assurance that we will be able to resolve existing and potential deferrals on favorable terms, or at all.

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 been volatile. A decline in the

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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 2009, approximately 94% 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 biomass 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

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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. 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

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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. 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. Because of the shortage of trained coal miners in recent years, we have occasionally operated certain facilities without full staff and have at times 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 we were to experience a shortage of skilled labor, 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.

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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;
- a requirement that we devote significant management attention and resources to integrating acquired businesses and 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.

Delays or unexpected difficulties in the integration process could adversely affect our business, financial results and financial condition. Even if we are able to integrate acquired businesses and assets successfully, this integration may not result in the realization for the full benefits of synergies, cost savings and operational efficiencies that we expect or the achievement of these benefits within a reasonable period of time. In addition, we may not have discovered prior to acquiring them all known and unknown factors regarding acquired businesses or assets that could produce unintended and unexpected consequences for us. Undiscovered factors

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could result in us incurring financial liabilities, which could be material, and in us not achieving the expected benefits from the acquisitions within our desired time frames, if at all.

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 the section entitled Long-Term Coal Supply Arrangements.

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

For the year ended December 31, 2009, we derived approximately 23% 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, 2009, we had consolidated indebtedness of approximately $1.8 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

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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.

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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 the section entitled Liquidity and Capital Resources.

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, 2009, if we had purchased the 15.6 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 $476.2 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

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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, Other Regulations and Legislation

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 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

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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 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;

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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 the section entitled Environmental and Other Regulatory Matters 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. We are required to record new obligations as liabilities at fair value under generally accepted accounting principles. 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. 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

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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 surfa