PEABODY ENERGY CORP
Form 10-K
February 28, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the Fiscal Year Ended December 31, 2010**
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 1-16463

Peabody Energy Corporation
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**13-4004153** *(I.R.S. Employer Identification No.)*
701 Market Street, St. Louis, Missouri *(Address of principal executive offices)*	**63101** *(Zip Code)*

(314) 342-3400
Registrant s telephone number, including area code

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the voting stock held by non-affiliates (shareholders who are not directors or executive officers) of the Registrant, calculated using the closing price on June 30, 2010: Common Stock, par value $0.01 per share, $10.5 billion.

Number of shares outstanding of each of the Registrant s classes of Common Stock, as of February 11, 2011: Common Stock, par value $0.01 per share, 270,560,221 shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company s Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company s 2011 Annual Meeting of Shareholders (the Company s 2011 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

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CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements of our expectations, intentions, plans and beliefs that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 and are intended to come within the safe harbor protection provided by those sections. These statements relate to future events or our future financial performance, including, without limitation, the section captioned Outlook in Management s Discussion and Analysis of Financial Condition and Results of Operations. We use words such as anticipate, believe, expect, may, project, should, estimate, or plan or other similar wo forward-looking statements.

Without limiting the foregoing, all statements relating to our future operating results, anticipated capital expenditures, future cash flows and borrowings, and sources of funding are forward-looking statements and speak only as of the date of this report. These forward-looking statements are based on numerous assumptions that we believe are reasonable, but are subject to a wide range of uncertainties and business risks and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ materially are:

- demand for coal in the United States (U.S.) and the Pacific Rim thermal and metallurgical coal seaborne markets;
- price volatility and demand, particularly in higher-margin products and in our trading and brokerage businesses;
- impact of weather on demand, production and transportation;
- reductions and/or deferrals of purchases by major customers and ability to renew sales contracts;
- credit and performance risks associated with customers, suppliers, co-shippers, and trading, banks and other financial counterparties;
- geologic, equipment, permitting and operational risks related to mining;
- transportation availability, performance and costs;
- availability, timing of delivery and costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires;
- successful implementation of business strategies, including our Btu Conversion and generation development initiatives;
- negotiation of labor contracts, employee relations and workforce availability;
- changes in postretirement benefit and pension obligations and their related funding requirements;
- replacement and development of coal reserves;
- availability, access to and the related cost of capital and financial markets;
- effects of changes in interest rates and currency exchange rates (primarily the Australian dollar);

effects of acquisitions or divestitures;

economic strength and political stability of countries in which we have operations or serve customers;

legislation, regulations and court decisions or other government actions, including new environmental requirements, changes in income tax regulations or other regulatory taxes;

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- litigation, including claims not yet asserted;
- terrorist attacks or threats;
- impacts of pandemic illnesses; and
- other factors, including those discussed in Legal Proceedings, set forth in Item 3 of this report and Risk Factors, set forth in Item 1A of this report.

When considering these forward-looking statements, you should keep in mind the cautionary statements in this document and in our other Securities and Exchange Commission (SEC) filings. These forward-looking statements speak only as of the date on which such statements were made, and we undertake no obligation to update these statements except as required by the federal securities laws.

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Note: The words we, our, Peabody or the Company as used in this report, refer to Peabody Energy Corporation or its applicable subsidiary or subsidiaries. Unless otherwise noted herein, disclosures in this Annual Report on Form 10-K relate only to our continuing operations.

PART I

Item 1. *Business.*

History and Development of Business

Peabody Energy Corporation is the world s largest private-sector coal company. We own majority interests in 28 coal mining operations located in the U.S. and Australia. In addition to our mining operations, we market, broker and trade coal through our Trading and Brokerage segment.

We were incorporated in Delaware in 2001 and our history in the coal mining business dates back to 1883. Over the past decade, we have continually adjusted our business to focus on the highest-growth regions in the U.S. and Asia-Pacific markets. As part of this transformation, we have made strategic acquisitions and divestitures in Australia and the U.S. After re-entering the Australian market in 2002, we expanded our presence there with acquisitions in 2004 and 2006. In 2007, we spun off portions of our formerly Eastern U.S. Mining segment through a dividend of all outstanding shares of Patriot Coal Corporation (Patriot). We have also continued to expand our Trading and Brokerage operations and now have a global trading platform with offices in the U.S., Europe, Australia and Asia.

Our future plans include advancing multiple organic growth projects in Australia and the U.S. that involve new mines, as well as the expansion and extension of existing mines. We also have a number of initiatives underway to expand our presence in the Asia-Pacific region, some of which include sourcing coal to be sold through our Trading and Brokerage segment and partnering with other companies to utilize our mining experience for joint mine development.

We have four core strategies to achieve growth:

1) Executing the basics of best-in-class safety, operations and marketing;

2) Capitalizing on organic growth opportunities;

3) Expanding in high-growth global markets; and

4) Participating in new generation and Btu Conversion technologies designed to expand the uses of coal technologies, including carbon capture and storage.

Segments

Our operations consist of four principal segments: our three mining segments and our Trading and Brokerage segment. Our three mining segments are Western U.S. Mining, Midwestern U.S. Mining and Australian Mining. Our fifth segment, Corporate and Other, includes mining and export/transportation joint ventures, energy-related commercial activities as well as the management of our vast coal reserve and real estate holdings. Our operating segments are discussed in more detail below with financial information contained in Note 22 to our consolidated financial statements.

Mining Segments

Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado mines, and our Midwestern U.S. Mining operations consist of our Illinois and Indiana mines. The principal business of our U.S. Mining segments is the mining, preparation and sale of thermal (steam) coal, sold primarily to electric utilities. Our Australian Mining operations consist of metallurgical and thermal coal mines in Queensland and New South Wales, Australia.

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The maps below display our mine locations as of December 31, 2010. Also noted are the primary ports utilized in the U.S. and in Australia for our coal exports and our corporate headquarters.

U.S. Mining Operations

Australian Mining Operations

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The table below presents information regarding each of our 28 mines, including mine location, type of mine, mining method, coal type, transportation method and tons sold in 2010. The mines are sorted by tons sold within each mining segment.

Mine	Location	Mine Type	Mining Method	Coal Type	Transport Method	2010 Tons Sold (In millions)
Western U.S. Mining						
North Antelope Rochelle	Wright, WY	S	DL, T/S	Thermal	R	105.8
Caballo	Gillette, WY	S	D, T/S	Thermal	R	23.5
Rawhide	Gillette, WY	S	D, T/S	Thermal	R	11.3
Twentymile	Oak Creek, CO	U	LW	Thermal	R, T	7.1
Kayenta	Kayenta, AZ	S	DL, T/S	Thermal	R	7.8
El Segundo	Grants, NM	S	T/S	Thermal	R	6.6
Lee Ranch	Grants, NM	S	DL, T/S	Thermal	R	1.7
Midwestern U.S. Mining						
Somerville Central	Oakland City, IN	S	DL, D, T/S	Thermal	R, T/R, T/B	3.3
Viking Corning Pit	Cannelburg, IN	S	D, T/S	Thermal	T, T/R	3.2
Gateway	Coulterville, IL	U	CM	Thermal	T, R, R/B	3.0
Willow Lake	Equality, IL	U	CM	Thermal	T/B	2.9
Bear Run	Sullivan County, IN	S	DL, D, T/S	Thermal	T, R	2.8
Francisco Underground	Francisco, IN	U	CM	Thermal	R	2.7
Cottage Grove	Equality, IL	S	D, T/S	Thermal	T/B	2.1
Somerville North(1)	Oakland City, IN	S	D, T/S	Thermal	R, T/R, T/B	2.0
Somerville South(1)	Oakland City, IN	S	D, T/S	Thermal	R, T/R, T/B	1.7
Air Quality	Vincennes, IN	U	CM	Thermal	T, T/R, T/B	1.1
Wildcat Hills Underground	Eldorado, IL	U	CM	Thermal	T/B	0.7
Wild Boar	Lynville, IN	S	D, T/S	Thermal	T, R, R/B	0.1
Other(2)						4.1
Australian Mining						
Wilpinjong*	Wilpinjong, New South Wales	S	T/S	Thermal	R, EV	9.2
North Wambo Underground(1)	Warkworth, New South Wales	U	LW	Thermal/Met**	R, EV	3.6
Wambo Open-Cut(1)*	Warkworth, New South Wales	S	T/S	Thermal	R, EV	3.0
Burton*(3)	Glenden, Queensland	S	T/S	Thermal/Met**	R, EV	2.6
North Goonyella	Glenden, Queensland	U	LW	Met**	R, EV	2.5
Wilkie Creek	Macalister, Queensland	S	T/S	Thermal	R, EV	1.7
Metropolitan	Helensburgh, New South Wales	U	LW	Met**	R, EV	1.7

Millennium*	Moranbah, Queensland	S	T/S	Met**	R, EV	1.6
Eaglefield*	Glenden, Queensland	S	T/S	Met**	R, EV	1.1

Legend:

S	Surface Mine	R	Rail
U	Underground Mine	T	Truck
DL	Dragline	R/B	Rail and Barge
D	Dozer/Casting	T/B	Truck and Barge
T/S	Truck and Shovel	T/R	Truck and Rail
LW	Longwall	EV	Export Vessel
CM	Continuous Miner	Thermal	Thermal/Steam
		Met	Metallurgical

* Mine is operated by a contract miner

** Metallurgical coals range from pulverized coal injection (PCI) to high quality hard coking coal on the heat value scale.

(1) Represents mines that have non-controlling ownership interests.

(2) Other in Midwestern U.S. Mining primarily consists of purchased coal used to satisfy certain coal supply agreements and shipments made from operations closed during 2010.

(3) The Burton Mine is a 95% proportionally owned and consolidated mine.

See Item 2. Properties for additional information regarding coal reserves, coal characteristics and tons produced for each mine.

Trading and Brokerage Segment

Through our Trading and Brokerage segment, we broker coal sales of other coal producers both as principal and agent, and trade coal, freight and freight-related contracts. We also provide transportation-related services in support of our coal trading strategy, as well as hedging activities in support of our mining operations.

Our primary trading offices are in St. Louis, Missouri, London, England, Newcastle, Australia and Singapore. We also have sales, marketing and business development offices in Beijing, China and Jakarta, Indonesia to pursue potential long-term growth opportunities in the Asian market.

Corporate and Other Segment

Resource Management. We hold approximately 9.0 billion tons of proven and probable coal reserves and more than 500,000 acres of surface property. Our resource development group regularly reviews these reserves for opportunities to generate earnings and cash flow through the sale of non-strategic coal reserves and surface land. In addition, we generate revenue through royalties from coal reserves and oil and gas rights leased to third parties and farm income from surface land under third-party contracts.

Export Facilities. We own a 37.5% interest in Dominion Terminal Associates, a partnership that operates a coal export terminal in Newport News, Virginia. The facility has a rated throughput capacity of approximately 20 million tons of coal per year and had 14.1 million tons of throughput in 2010. The facility also has ground storage capacity of approximately 1.7 million tons. The facility exports both metallurgical and thermal coal primarily to European and Brazilian markets.

We own a 17.7% interest in the Newcastle Coal Infrastructure Group (NCIG), a coal transloading facility in Newcastle, Australia. The total loading capacity for stage one is 33 million tons per year, of which our share is 5.8 millions tons. In 2010, stage one of construction was substantially completed and operations commenced. NCIG is currently operating at a reduced rate as part of its ramp-up to full capability, which is anticipated to occur by late 2011. Phase one of stage two construction has been approved and is under way. When complete, it is expected to provide us with approximately 2 million tons of additional annual throughput capacity beginning in mid-2012.

We are currently investigating the potential for a west coast port which will allow us to export Powder River Basin coal to Asian markets.

Generation Development and Btu Conversion. To maximize our coal assets and land holdings for long-term growth, we are contributing to the development of coal-fueled generation, pursuing Btu Conversion projects that would convert coal to natural gas or transportation fuels and advancing clean coal technologies.

Generation development projects involve using our surface lands and coal reserves as the basis for mine-mouth plants. We are a 5.06% owner in the Prairie State Energy Campus (Prairie State), a 1,600 megawatt coal-fueled electricity generation project under construction in Washington County, Illinois. Prairie State will be fueled by over six million tons of coal each year produced from its adjacent underground mining operations. We sold 94.94% of the land and coal reserves to our partners in Prairie State and we are responsible for our 5.06% share of costs to construct the facility. The facility is scheduled to begin generating electricity in 2011. We currently expect to market and sell our share of electricity generated by the facility.

Btu Conversion involves projects designed to expand the uses of coal through coal-to-liquids (CTL) and coal gasification technologies. Currently, we are pursuing development of a coal-to-gas (CTG) facility known as Kentucky NewGas, a planned mine-mouth gasification project using ConocoPhillips proprietary E-Gas™ technology to produce clean synthesis gas with carbon storage potential. We also own an equity interest in GreatPoint Energy, Inc., which is commercializing its coal-to-pipeline quality natural gas technology. We are pursuing a project with the government of Inner Mongolia and other Chinese partners to explore development opportunities for a large surface mine and downstream coal gasification facility that would produce methanol, chemicals or fuel products.

Clean Coal Technology. We continue to support clean coal technology development and other green coal initiatives seeking to reduce global atmospheric levels of carbon dioxide and other emissions. We are the only non-Chinese equity partner in GreenGen, which is constructing a near-zero emissions coal-fueled power plant with carbon capture and storage (CCS) near Tianjin, China. The first phase of GreenGen operations is expected to be online in 2011. In Australia, we made a 10-year commitment to the Australian COAL21 Fund designed to support clean coal technology demonstration projects and research in Australia.

We are also a founding member of the Global Carbon Capture and Storage Institute, an international initiative to accelerate commercialization of CCS technologies through development of 20 integrated, industrial-scale demonstration projects, as well as a participant in the Power Systems Development Facility, the PowerTree Carbon Company LLC, the Midwest Geopolitical Sequestration Consortium, the Asia-Pacific Partnership for Clean Development and Climate, the U.S.-China Energy Cooperation Program, the Consortium for Clean Coal Utilization, the National Carbon Capture Center and the Western Kentucky Carbon Storage Foundation.

In 2010, we acquired an equity interest in Calera Corp., which is developing proprietary technology that converts captured carbon dioxide into building materials.

In the U.S., The Domenici-Barton Energy Policy Act of 2005 contained tax incentives and directed spending totaling an estimated $14.1 billion intended to stimulate U.S. supply-side energy growth and increased efficiency, including a coal-related package estimated at nearly $3 billion.

Clean coal technology development in the U.S. is being accelerated by the American Recovery and Reinvestment Act of 2009, which targeted $3.4 billion for a Department of Energy (DOE) fossil fuel programs, including: $1 billion for CCS research; $800 million for the Clean Coal Power Initiative, a 10-year program supporting commercial CCS; and $50 million for geology research.

In addition, in February 2010, President Obama announced the formation of an Interagency Task Force on Carbon Capture and Storage (the Task Force) to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of clean coal technologies. The Task Force has been asked to develop a proposed plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to 10 commercial demonstration projects online by 2016.

Mongolia Joint Venture. In 2009, we acquired a 50% interest in a joint venture with Polo Resources Limited (Polo), which holds coal and mineral interests in Mongolia. In 2010, Winsway Coking Coal Holdings Ltd. (Winsway) purchased the 50% interest in the joint venture formerly owned by Polo and we entered into a joint venture agreement with Winsway, creating Peabody-Winsway Resources B.V. The joint venture is in the development stage and plans to ship metallurgical and thermal coal to Asian markets once developed. Winsway is one of the leading suppliers in China of imported high-quality coking coal. It distributes and transports coal from Mongolia and other countries into China through its integrated service platform which includes logistics parks, coal washing plants, and road and railway transportation capabilities along the coast, rivers and inland borders of China, including Inner Mongolia.

Paso Diablo Mine. We own a 48.37% interest in Carbones del Guasare S.A., which operates the Paso Diablo Mine, a surface operation in northwestern Venezuela that produces thermal coal for export primarily to the U.S. and Europe. We began 2010 with a 25.5% ownership interest in the joint venture. During 2010, we acquired Anglo American plc s 25.5% ownership interest in the joint venture and transferred 2% of our ownership interest to Carbones del Zulia S.A. as part of the acquisition. We are responsible for marketing our pro-rata share of sales from Paso Diablo; the joint venture is responsible for production, processing and transportation of coal to ocean-going vessels for delivery to customers.

Captive Insurance Entity. A portion of our insurance risks associated with workers compensation, general liability and auto liability coverage is self-insured through a wholly-owned captive insurance company.

The captive entity invoices certain of our subsidiaries for the premiums on these policies, pays the related claims, maintains reserves for anticipated losses and invests funds to pay future claims.

Coal Supply Agreements

Our coal supply agreements are primarily with electricity generators, industrial facilities and steel manufacturers. Most of our sales (excluding trading transactions) are made under long-term coal supply agreements (those with terms longer than one year). Sales under such agreements comprised approximately 91%, 93% and 90% of our worldwide sales (by volume) for the years ended December 31, 2010, 2009 and 2008, respectively.

For the year ended December 31, 2010, we derived 25% of our total coal sales revenues from our five largest customers. Those five customers were supplied primarily from 37 coal supply agreements (excluding trading transactions) expiring at various times from 2011 to 2016. The contract contributing the greatest amount of annual revenue in 2010 was approximately $279 million, or approximately 4% of our 2010 total revenue base.

Our sales backlog includes coal supply agreements subject to price reopener and/or extension provisions. As of January 31, 2011 and 2010, we had a sales backlog of over 1 billion tons of coal. Contracts in backlog have remaining terms ranging from one to 16 years, representing over four years of production based on our 2010 production of 218.4 million tons. As of January 31, 2011, approximately 78% of our backlog is expected to be filled beyond one year.

U.S. We expect to continue selling a significant portion of our coal under long-term supply agreements. Customers continue to pursue long-term sales agreements as the importance of reliability, service and predictable prices are recognized. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these agreements vary significantly in many respects, including price adjustment features, price reopener terms, coal quality requirements, quantity parameters, permitted sources of supply, treatment of environmental constraints, extension options, force majeure and termination and assignment provisions. Our strategy is to selectively renew, or enter into new, long-term supply agreements when we can do so at prices we believe are favorable.

Australia. Our Australian coal mining activities accounted for 12% of our mining operations sales volume in 2010 and 10% in 2009 and 2008. Our production is sold primarily into the export metallurgical and thermal markets. Historically, we predominately entered into multi-year international coal agreements that contained provisions allowing either party to commence a renegotiation of the agreement price annually in the second quarter of each year. Current industry practice, and our practice, is to negotiate pricing for metallurgical coal contracts quarterly and seaborne thermal coal contracts annually.

Transportation

Coal consumed in the U.S. is usually sold at the mine with transportation costs borne by the purchaser. Australian and U.S. export coal is usually sold at the loading port, with purchasers paying ocean freight. Producers usually pay shipping costs from the mine to the port, including any demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time). Demurrage continues to be part of the shipping costs for our Australian exports as certain ports continue to experience vessel queues due to factors such as lower than expected rail performance, supply constraints, adverse weather and delays in coal availability from time-to-time with those with whom we share vessels (co-shippers).

We believe we have good relationships with rail carriers and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation coordinators. See the table on page 4 for transportation methods by mine.

One of our primary ports in the U.S. for exporting metallurgical and thermal coal is through the Dominion Terminal Associates coal terminal in Newport News, Virginia. In Australia, our primary ports in Queensland through which we export both metallurgical and thermal coal are the Dalrymple Bay and Brisbane coal terminals. In New South Wales, our primary ports for exporting metallurgical and thermal coal are at Port Kembla and Newcastle, which includes the terminal operated by NCIG that opened in 2010.

Suppliers

The main types of goods we purchase in support of our mining activities are mining equipment and replacement parts, diesel fuel, ammonium-nitrate and emulsion-based explosives, off-the-road (OTR) tires, steel-related (including roof control materials) products, lubricants and electricity. For some of these goods, there has been some consolidation in the supplier base providing mining materials to the coal industry, such as with suppliers of explosives and both surface and underground equipment, that has limited the number of sources for these materials. In situations where we have chosen to concentrate a large portion of purchases with one supplier, it has been to take advantage of cost savings from larger volumes of purchases and to ensure security of supply. We have many well-established, strategic relationships with our key suppliers of goods and do not believe we are dependent on any of our individual suppliers.

In recent years, demand and lead times for certain surface and underground mining equipment and OTR tires has increased. However, we do not expect lead times to have a near-term material impact on our financial condition, results of operations or cash flows due to the strategic and contractual relationships we have with these suppliers.

We also purchase services at our mine sites that include maintenance services for mining equipment, temporary labor and other various contracted services, including contract miners and explosive service providers. We do not believe that we are dependent on any of our individual service providers.

Technical Innovation

We continue to emphasize the application of technical innovation to improve new and existing equipment performance. This effort is typically undertaken and funded by equipment manufacturers with our engineering, maintenance and purchasing personnel providing input and expertise to the manufacturers that will design and produce equipment that we believe will add value to the business.

Since 2009 we have been upgrading the mining equipment at our North Antelope Rochelle Mine, both to increase overburden removal capacity and improve mining cost with larger more efficient trucks and shovels. This effort continued in 2010 with the commissioning of new shovels and ultra class haul trucks.

Our engineers continue to work with several major equipment vendors to develop designs for in-pit crushing and conveying systems to displace trucks and dozers to move large quantities of overburden at a reduced cost and in a more environmentally friendly manner. We are in the process of commissioning the Landmark longwall automation technology at our North Wambo Underground Mine and working with longwall original equipment manufacturers to incorporate similar technology at our Metropolitan Mine. This system includes hardware and software that monitors and controls the pitch, roll and depth of cut of the shearer to maintain the face alignment, allowing the shearer to mine more efficiently.

In 2011, we will be testing a proximity detection system at our Willow Lake Mine. The system is being designed to automatically stop mining equipment if a person is detected within the operating range of the equipment.

At our Metropolitan Mine, we continue with pilot testing of a pumping system that will allow coal refuse from the mine to be disposed of in abandoned areas of the underground workings rather than transported to the surface. During 2010, test trials were successfully completed on the backfill process and the installation of the pumping system is nearing completion. Underground emplacement is expected to commence in the first quarter 2011.

Our enterprise resource planning system provides detailed equipment and mining performance data for all our U.S. operations. Proprietary software for hand-held Personal Digital Assistant devices was developed in-house, and has been deployed at all U.S. underground mines to record safety observations, safety audits, underground front-line supervisor reports and delay information. Wireless data acquisition systems are installed at three of our largest surface mines, North Antelope Rochelle, Caballo and Bear Run, to dispatch mobile equipment more efficiently and monitor performance and condition of all major mining equipment on a real-time basis. In addition, data historians are being installed at our North Antelope Rochelle and Bear Run mines, to further analyze operational performance in order to improve future performance.

We use maintenance standards based on reliability-centered maintenance practices at all operations to increase equipment utilization and reduce maintenance and capital spending by extending the equipment life, while minimizing the risk of premature failures. Specialized maintenance reliability software is used at many operations to better support improved equipment strategies, predict equipment condition and aid analysis necessary for better decision-making for such issues as component replacement timing. We also use in-house developed software to schedule and monitor trains, mine and pit blending, quality and customer shipments to enhance our reliability and product consistency.

Competition

The markets in which we sell our coal are highly competitive. We compete on the basis of coal quality, delivered price, customer service and support and reliability. Demand for coal and the prices that we will be able to obtain for our coal are influenced by factors beyond our control, including the demand for electricity and steel and the availability and price of alternative fuels and energy sources. Our principal U.S. competitors (listed alphabetically) are other large coal producers, including Alpha Natural Resources, Inc., Arch Coal, Inc., Cloud Peak Energy Inc., CONSOL Energy Inc. and Massey Energy Company, which collectively accounted for approximately 40% of total U.S. coal production in 2009 (most recent publicly available data according to the National Mining Association s 2009 Coal Producer Survey). Major international competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Rio Tinto, Shenhua Group and Xstrata PLC.

Employees

As of December 31, 2010, we had approximately 7,200 employees, which included approximately 5,100 hourly employees. As of such date, approximately 28% of our hourly employees were represented by organized labor unions and generated 9% of 2010 coal production. In the U.S., those represented by organized labor unions include hourly workers at our Kayenta Mine in Arizona and at our Willow Lake Mine in Illinois. In Australia, the coal mining industry is highly unionized and the majority of workers employed at our mining operations are members of trade unions. The Construction Forestry Mining and Energy Union represents our Australian subsidiary s hourly production and engineering employees, including those employed through contract mining relationships. All the Australian subsidiary s mine sites have enterprise bargaining agreements. Additional information on labor relations is contained in Note 18 to our consolidated financial statements.

Working Capital

We generally fund our business operations through a combination of available cash and equivalents and cash flow generated from operations. In addition, our revolving credit facility (Revolver) and our accounts receivable securitization program are available for additional working capital needs. See Liquidity and Capital Resources in Part II, Item 7 for additional information regarding working capital.

Regulatory Matters U.S.

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, the reclamation and restoration of mining properties after mining has been completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects of mining on groundwater quality and availability. In addition, the industry is affected by significant legislation mandating certain benefits for current and retired coal miners. Numerous federal, state and local governmental permits and approvals are required for mining operations. We believe that we have obtained all permits currently required to conduct our present mining operations.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry. None of our violations to date or the monetary penalties assessed has been material.

Mine Safety and Health. We are subject to health and safety standards both at the federal and state level. The regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations and other matters.

The Mine Safety and Health Administration (MSHA) is the entity responsible for monitoring compliance with the federal mine health and safety standards. MSHA has various enforcement tools that it can use, including the issuance of monetary penalties and orders of withdrawal from a mine or part of a mine. Some, but not all, of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to customers.

MSHA has recently taken a number of actions to identify mines with safety issues, and has engaged in a number of targeted enforcement, awareness, outreach and rulemaking activities to reduce the number of mining fatalities, accidents and illnesses. There has also been an industry-wide increase in the monetary penalties assessed for citations of a similar nature.

In Item 9B. Other Information, we provide additional details on how we monitor safety performance and MSHA compliance, as well as provide the mine safety disclosures required pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act).

Safety is a core value that is integrated into all areas of our business. Our goal is to provide a workplace that is incident free. We believe that it is our responsibility to our employees to provide a superior safety and health environment. We seek to implement this goal by: training employees in safe work practices; openly communicating with employees; establishing, following and improving safety standards; involving employees in safety processes; and recording, reporting and investigating accidents, incidents and losses to avoid reoccurrence. During 2010, we voluntarily idled our mines for one day to allow for interactive safety discussions with our employees, local and federal agency representatives and management, and to provide additional comprehensive training on accident prevention, violation awareness and reduction and emergency preparedness.

As part of our training, we collaborate with MSHA and other government agencies to identify and test emerging safety technologies.

We also partner with several companies and governmental agencies to pursue new technologies that have the potential to improve our safety performance and provide better safety protections for our employees. We have signed letters of intent to field test a new mine emergency vehicle under development by outside companies. We will begin installation of a new communications and tracking system at our U.S. underground mines, which will allow persons on the surface to determine the location of and communicate with all persons underground. In addition, we are exploring the use of proximity detection and collision avoidance systems to enhance the safety around our large equipment fleets.

Black Lung. Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees and last worked for the operator after July 1, 1973. Coal mine operators must also make payments 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. Historically, less than 7% of the miners currently seeking federal black lung benefits are awarded these benefits. The trust fund is funded by an excise tax on U.S. production of up to

$1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

Environmental Laws. We are subject to various federal and state environmental laws. Some of these laws, discussed below, place many requirements on our coal mining operations. Federal and state regulations require regular monitoring of our mines and other facilities to ensure compliance.

Surface Mining Control and Reclamation Act. In the U.S., the Surface Mining Control and Reclamation Act of 1977 (SMCRA), which is administered by the Office of Surface Mining Reclamation and Enforcement (OSM), established mining, environmental protection and reclamation standards for all aspects of U.S. surface mining as well as many aspects of deep mining. Mine operators must obtain SMCRA permits and permit renewals for mining operations from the OSM. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the regulatory authority. Except for Arizona, states in which we have active mining operations have achieved primary control of enforcement through federal authorization. In Arizona, we mine on tribal lands and are regulated by OSM because the tribes do not have SMCRA authorization.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness and technical review. Public notice of the proposed permit is given for a comment period before a permit can be issued. Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine and often take six months to two years to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has the right to comment on and otherwise engage in the permitting process, including public hearings and through intervention in the courts. Before a SMCRA permit is issued, a mine operator must submit a bond or other form of financial security to guarantee the performance of reclamation obligations.

The Abandoned Mine Land Fund, which is part of SMCRA, requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund. The fee was $0.35 per ton of surface-mined coal and $0.15 per ton of deep-mined coal, effective through September 30, 2007. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 through September 30, 2012, the fee is $0.315 per ton of surface-mined coal and $0.135 per ton of underground mined coal. From October 1, 2012 through September 30, 2021, the fee will be reduced to $0.28 per ton of surface-mined coal and $0.12 per ton of underground mined coal.

SMCRA stipulates compliance with many other major environmental programs. These programs include the Clean Air Act; Clean Water Act; Resource Conservation and Recovery Act (RCRA); and Comprehensive Environmental Response, Compensation, and Liability Acts (CERCLA, commonly known as Superfund). Besides OSM, other federal regulatory agencies are involved in monitoring or permitting specific aspects of mining operations. The U.S. Environmental Protection Agency (EPA) is the lead agency for states or tribes with no authorized programs under the Clean Water Act, RCRA and CERCLA. The U.S. Army Corps of Engineers regulates activities affecting navigable waters and waters of the U.S., including wetlands, and the U.S. Bureau of Alcohol, Tobacco and Firearms regulates the use of explosive blasting materials.

We do not believe there are any matters that pose a material risk to maintaining our existing mining permits or that materially hinder our ability to secure future mining permits. It is our policy to comply with the requirements of the SMCRA and the state and tribal laws and regulations governing mine reclamation.

Clean Air Act. The Clean Air Act and the comparable state laws that regulate the emissions of materials into the air affect U.S. coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations may occur through the Clean Air Act permitting requirements and/or emission control requirements relating to particulate matter. It is possible that the more stringent national ambient air quality standards (NAAQS) will directly impact our mining operations by, for example, requiring additional controls of emissions from our mining equipment and vehicles. Moreover, if the areas in which our mines and coal preparation plants are located suffer from extreme weather events such as droughts, or are designated as non-attainment areas, we could be required to incur significant costs to install additional emissions control equipment, or otherwise change our operations and future development. In addition, in September 2009 the EPA adopted new rules tightening and adding additional particulate matter emissions limits for coal preparation and processing plants constructed, reconstructed or modified after April 28, 2008.

The Clean Air Act indirectly, but more significantly, affects the coal industry by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury, particulate matter and other substances emitted by coal-based electricity generating plants. Air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the Acid Rain Program, NOx SIP Call, the Clean Air Interstate Rule (CAIR) as well as the Transport Rule the EPA proposed in July 2010 to replace it, Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and New Source Review. In addition, in recent years the EPA has adopted more stringent NAAQS for particulate matter, nitrogen oxide and sulfur dioxide and has proposed a more stringent NAAQS for ozone. EPA is under a court order to promulgate new MACT rules for electric generating units by November 16, 2011. Many of these programs and regulations have resulted in litigation which has not been completely resolved.

In December 2009, the EPA published its finding that atmospheric concentrations of greenhouse gases endanger public health and welfare within the meaning of the Clean Air Act, and that emissions of greenhouse gases from new motor vehicles and new motor vehicle engines are contributing to air pollution that are endangering public health and welfare within the meaning of the Clean Air Act. In May 2010, the EPA published final greenhouse gas emission standards for new motor vehicles pursuant to the Clean Air Act. Both the endangerment finding and motor vehicle standards are the subject of litigation.

Because the Clean Air Act specifies that the prevention of significant deterioration program applies once emissions of regulated pollutants exceed either 100 or 250 tons per year (depending on the type of source), millions of sources previously unregulated under the Clean Air Act could be subject to greenhouse gas reduction measures. The EPA published a rule in June 2010 to limit the number of greenhouse gas sources that would be subject to the prevention of significant deterioration (PSD) program. In the so-called tailoring rule, the EPA limited the regulation of greenhouse gases from certain stationary sources to those that emit more than 75,000 tons of greenhouse gases per year (for sources that would be subject to PSD permitting regardless of greenhouse gas emissions due to other air emissions) or 100,000 tons of greenhouse gases per year (for sources not subject to PSD permitting for any other air emissions), measured by carbon dioxide equivalent. Whether the EPA has the statutory authority under the Clean Air Act to adopt the tailoring rule also is the subject of litigation.

In December 2010, EPA announced a settlement with states and environmental groups that had filed litigation challenges to EPA s decisions not to establish greenhouse gas emission standards for fossil fuel-fired power plants and for petroleum refineries under section 111 of the Clean Air Act. In the settlement, the EPA agreed: (1) to sign proposed new source performance standards for new and modified electric utility steam generating units under section 111(b), as well as proposed guidelines for states development of emission standards for existing electric utility steam generating units under section 111(d), by July 26, 2011; and (2) to take final action on the proposed section 111(b) standards and section 111(d) guidelines by May 26, 2012. Whatever the EPA determines the new source performance standards to be, this will then be the minimum requirement for best available control technology requirements under the prevention of significant deterioration program.

Clean Water Act. The Clean Water Act of 1972 affects U.S. coal mining operations by requiring both technology-based and, if necessary, water quality-based effluent limitations and treatment standards for wastewater discharge through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting requirements and performance standards are requirements of NPDES permits that govern the discharge of pollutants from mine-related point sources into water. Section 404 of the Clean Water Act requires mining companies to obtain U.S. Army Corps of Engineers permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities.

States are empowered to develop and apply in stream water quality standards. These standards are subject to change and must be approved by the EPA. Discharges must either meet state water quality standards or be authorized through available regulatory processes such as alternate standards or variances. In stream standards vary from state to state. Additionally, through the Clean Water Act section 401 certification program, states have approval authority over federal permits or licenses that might result in a discharge to their waters. States consider whether the activity will comply with their water quality standards and other applicable requirements in deciding whether or not to certify the activity.

Resource Conservation and Recovery Act. RCRA, which was enacted in 1976, affects U.S. coal mining operations by establishing cradle to grave requirements for the treatment, storage and disposal of hazardous wastes. Typically, the only hazardous wastes generated at a mine site are those from products used in vehicles and for machinery maintenance. Coal mine wastes, such as overburden and coal cleaning wastes, are not considered hazardous wastes under RCRA.

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 materials generated at electric utility and independent power producing facilities. In May 2000, the EPA concluded that coal combustion materials do not warrant regulation as hazardous wastes under RCRA. The EPA has retained the hazardous waste exemption for these materials. The EPA is evaluating national waste guidelines for coal combustion materials placed at a mine. National guidelines for mine-fills may affect the cost of ash placement at mines. The EPA revisited its May 2000 determination and proposed new requirements for coal combustion residue (CCR) management on June 21, 2010. That proposal contains two options: (1) to continue to regulate CCR as a non-hazardous waste, or (2) to regulate CCR as special waste under the hazardous waste regulations.

CERCLA (Superfund). CERCLA affects U.S. coal mining and hard rock operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under CERCLA, joint and several liabilities may be imposed on waste generators, site owners or operators and others regardless of fault. Under the EPA s Toxic Release Inventory process, companies are required annually to report the use, manufacture or processing of listed toxic materials that exceed defined thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers.

Endangered Species Act. The U.S. Endangered Species Act and counterpart state legislation is intended to protect species whose populations allow for categorization as either endangered or threatened. With respect to obtaining mining permits, protection of endangered or threatened species may have the effect of prohibiting, limiting the extent or causing delays that may include permit conditions on the timing of soil removal, timber harvesting, road building and other mining or agricultural activities in areas containing the affected species. Based on the species that have been identified on our properties and the current application of these laws and regulations, we do not believe that they will have a material adverse effect on our ability to mine the planned volumes of coal from our properties in accordance with current mining plans. However, there are ongoing lawsuits and petitions under these laws and regulations that, if successful, could have a material adverse effect on our ability to mine some of our properties in accordance with our current mining plans.

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 federal regulatory requirements.

Regulatory Matters Australia

The Australian mining industry is regulated by Australian federal, state and local governments with respect to environmental issues such as land reclamation, water quality, air quality, dust control, noise, planning issues (such as approvals to expand existing mines or to develop new mines), and health and safety issues. The Australian federal government retains control over the level of foreign investment and export approvals. Industrial relations are regulated under both federal and state laws. Australian state governments also require coal companies to post deposits or give other security against land which is being used for mining, with those deposits being returned or security released after satisfactory reclamation is completed.

Native Title and Cultural Heritage. Since 1992, the Australian courts have recognized that native title to lands, as recognized under the laws and customs of the Aboriginal inhabitants of Australia, may have survived the process of

European settlement. These developments are supported by the Federal Native Title Act which recognizes and protects native title, and under which a national register of native title claims has been established. Native title rights do not extend to minerals; however, native title rights can be affected by the mining process unless those rights have previously been extinguished. There is also federal and state legislation to prevent damage to Aboriginal cultural heritage and archeological sites.

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Mining Tenements and Environmental. In Queensland and New South Wales, the development of a mine requires both the grant of a right to and also an approval which authorizes the environmental impacts of the mine. These approvals are obtained under separate legislation from separate government authorities. However, the application processes run concurrently and are also concurrent with any native title or cultural heritage process that is required. The environmental impacts of mining projects are regulated by state and federal governments. Federal regulation will only apply if the particular project will significantly impact a matter of national environmental significance (e.g., endangered species or particular protected places). If so, it will also be regulated by the federal government.

Occupational Health and Safety. The combined effect of various state and federal statutes requires an employer to ensure that persons employed in a mine are safe from injury by providing a safe working environment and systems of work; safety machinery; equipment, plant and substances; and appropriate information, instruction, training and supervision. Currently all states and territories are responsible for making and enforcing their own laws. Although these draw on a similar approach for regulating workplaces, there are some differences in the application and detail of the laws. However, in December 2009, the Workplace Relations Ministers Council endorsed a model Work Health and Safety Act. Each of the states and territories has agreed to implement their own legislation adopting the model legislation by December 2011 to achieve consistent requirements across the country.

In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under state legislation that deals specifically with the coal mining industry. Mining employers, owners, directors and managers, persons in control of work places, mine managers, supervisors and employees are all subject to these duties.

Industrial Relations. A national industrial relations system administered by the federal government applies to all private sector employers and employees. The system largely became operational in July 2009 and fully operational in January 2010. The matters regulated under the national system include employment conditions, unfair dismissal, enterprise bargaining, industrial action and resolution of workplace disputes.

National Greenhouse and Energy Reporting Act 2007 (NGER Act). The NGER Act introduces a single national reporting system relating to greenhouse gas emissions and energy production and consumption, which will underpin a future emissions trading scheme. The NGER Act imposes requirements for certain corporations to report greenhouse gas emissions and abatement actions, as well as energy production and consumption. Both foreign and local corporations that meet the prescribed CO_2 and energy production or consumption limits in Australia (controlling corporations) must comply with the NGER Act. One of our subsidiaries is now registered as a controlling corporation and must report each financial year about the greenhouse gas emissions and energy production and consumption of our Australian entities.

Regulatory Matters Mongolia

As noted above, we currently own a 50% interest in the Peabody-Winsway Resources B.V. joint venture, which holds coal and mineral interests in Mongolia and is regulated by Mongolian federal, provincial and local governments with respect to exploration, development, production, occupational health, mine safety, water use, environmental protection and remediation, foreign investment and other related matters. The Mineral Resources Authority of Mongolia is the government agency with the authority to issue, extend and revoke mineral licenses, which generally give the license holder the right to engage in the mining of minerals within the license area for 30 years (with the right to extend for two additional periods of 20 years). Mongolian law provides for state participation in the exploitation of any mineral deposit of strategic importance, as determined by the Mongolian Parliament.

Global Climate

In the U.S., Congress has considered legislation addressing global climate issues and greenhouse gas emissions, but to date nothing has been enacted. While it is possible that the U.S. will adopt legislation in the future, the timing and specific requirements of any such legislation are uncertain. In the absence of new U.S. federal legislation, the EPA is attempting to regulate greenhouse gas emissions pursuant to the Clean Air

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Act. In response to the 2007 U.S. Supreme Court ruling in Massachusetts v. EPA, the EPA has commenced several rulemaking projects as described above under Regulatory Matters-U.S. Clean Air Act.

A number of states in the U.S. have adopted programs to regulate greenhouse gas emissions. For example, 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont) have formed the Regional Greenhouse Gas Initiative, which is a mandatory cap-and-trade program to reduce carbon dioxide emissions from power plants. Six midwestern states (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) and one Canadian province have entered into the Midwestern Regional Greenhouse Gas Reduction Accord to establish voluntary regional greenhouse gas reduction targets and develop a voluntary multi-sector cap-and-trade system to help meet the targets. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces have entered into the Western Climate Initiative (WCI) to establish a voluntary regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. However, the only two states prepared to go forward when the WCI begins on January 1, 2012 are California and New Mexico. The Governor of Arizona announced in February 2010 that Arizona will not implement the greenhouse gas cap-and-trade proposal advanced by the WCI. In 2006, the California legislature approved legislation allowing the imposition of statewide caps on, and cuts in, carbon dioxide emissions. Similar legislation was adopted in 2007 in Hawaii, Minnesota and New Jersey. The California Air Resources Board is in the process of finalizing regulations to implement a cap-and-trade program pursuant to the 2006 legislation, and that program is expected to go into effect on January 1, 2012.

We participate in the DOE s Voluntary Reporting of Greenhouse Gases Program, and regularly disclose the quantity of emissions per ton of coal produced by us in the U.S. The vast majority of our emissions are generated by the operation of heavy machinery to extract and transport material at our mines.

The Kyoto Protocol, adopted in December 1997 by the signatories to the 1992 Framework Convention on Climate Change, established a binding set of emission targets for developed nations. The U.S. signed the Kyoto Protocol but it was not ratified by the U.S. Senate. Australia ratified the Kyoto Protocol in December 2007 and became a full member in March 2008. There are continuing discussions to develop a treaty to replace the Kyoto Protocol after its expiration in 2012, including the Cancun meetings in late 2010.

Australia s Parliament has considered legislation that would specifically address global climate issues and greenhouse gas emissions, but to date nothing has been enacted. While it is possible that Australia federal or state government may adopt legislation in the future, the timing and specific requirements of any such legislation are uncertain.

Enactment of laws or passage of regulations regarding emissions from the mining of coal by the U.S. or some of its states or by other countries, or other actions to limit such emissions, are not expected to have a material adverse effect on our results of operations, financial condition or cash flows.

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S. or some of its states or by other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources. The potential financial impact on us of future laws or regulations will depend upon the degree to which any such laws or regulations forces electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such laws or regulations, the time periods over which those laws or regulations would be phased in and the state of commercial development and deployment of CCS technologies. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws or regulations may have on our results of operations, financial condition or cash flows.

Additional Information

We file annual, quarterly and current reports, and our amendments to those reports, proxy statements and other information with the SEC. You may access and read our SEC filings free of charge through our website, at www.peabodyenergy.com, or the SEC s website, at www.sec.gov. Information on such websites does not constitute part of this document. You may also read and copy any document we file at the SEC s public reference room located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

You may also request copies of our filings, free of charge, by telephone at (314) 342-3400 or by mail at: Peabody Energy Corporation, 701 Market Street, Suite 900, St. Louis, Missouri 63101, attention: Investor Relations.

Item 1A. *Risk Factors.*

The following risk factors relate specifically to the risks associated with our continuing operations.

Risks Associated with Our Operations

A decline in coal prices could negatively affect our profitability.

Our profitability depends upon the prices we receive for our coal. Coal prices are dependent upon factors beyond our control, including:

- the demand for electricity and the strength of the global economy;
- the demand for steel, which may lead to price fluctuations in the quarterly and annual repricing of our metallurgical coal contracts;
- the supply of U.S. domestic and international thermal and metallurgical coal;
- adverse weather and natural disasters;
- competition within our industry and the availability and price of alternative fuels and energy sources;
- the proximity, capacity and cost of transportation;
- coal industry capacity;
- domestic and foreign governmental regulations and taxes, including those establishing air emission standards for coal-fueled power plants;
- regulatory, administrative and judicial decisions, including those affecting future mining permits; and
- technological developments, including those intended to convert coal-to-liquids or gas and those aimed at capturing and storing carbon dioxide.

In the U.S., our strategy is to selectively renew, or enter into new, long-term supply agreements when we can do so at prices we believe are favorable. In Australia, the current practice for metallurgical coal is quarterly contract pricing and for seaborne thermal coal is annual contract pricing. If we experience a weak coal pricing environment resulting in a deterioration of coal prices, we could experience an adverse effect on our revenues and profitability.

If a substantial number of our long-term coal supply agreements terminate, our revenues and operating profits could suffer if we are unable to find alternate buyers willing to purchase our coal on comparable terms to those in our contracts.

Most of our sales are made under coal supply agreements, which are important to the stability and profitability of our operations. The execution of a satisfactory coal supply agreement is frequently the basis on which we undertake the development of coal reserves required to be supplied under the contract, particularly in the U.S. In 2010, 91% of our worldwide sales volume was sold under long-term coal supply agreements. At January 31, 2011, our sales backlog, including backlog subject to price reopener and/or extension provisions, was over 1 billion tons, representing over four years of current production in backlog based on our 2010 production of 218.4 million tons. Contracts in backlog have remaining terms ranging from one to 16 years.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. We may adjust these contract prices based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. We sometimes experience a reduction in coal prices in new long-term coal supply agreements replacing some of our expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer during the duration of specified events beyond the control of the affected party. Most coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, grindability and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. Moreover, some of these agreements permit the customer to terminate the contract if transportation costs, which our customers typically bear, increase substantially. In addition, some of these contracts allow our customers to terminate their contracts in the event of changes in regulations affecting our industry that restricts the use or type of coal permissible at the customer s plant or increase the price of coal beyond specified limits.

The operating profits we realize from coal sold under supply agreements depend on a variety of factors. In addition, price adjustment and other provisions may increase our exposure to short-term coal price volatility provided by those contracts. If a substantial portion of our coal supply agreements were modified or terminated, we could be materially adversely affected to the extent that we are unable to find alternate buyers for our coal at the same level of profitability. Market prices for coal vary by mining region and country. As a result, we cannot predict the future strength of the coal market overall or by mining region and cannot provide assurance that we will be able to replace existing long-term coal supply agreements at the same prices or with similar profit margins when they expire.

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

For the year ended December 31, 2010 we derived 25% of our total coal sales revenues from our five largest customers. Those five customers were supplied primarily from 37 coal supply agreements (excluding trading transactions) expiring at various times from 2011 to 2016. The contract contributing the greatest amount of annual revenue in 2010 was approximately $279 million, or approximately 4% of our 2010 total revenue base. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and those customers may not continue to purchase coal from us under long-term coal supply agreements. If a number of these customers significantly reduce their purchases of coal from us, or if we are unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially. In addition, our revenue could be adversely affected by a decline in customer purchases due to lack of demand, cost of competing fuels and environmental regulations.

Our operating results could be adversely affected by unfavorable economic and financial market conditions.

In recent years, the global economic recession and the worldwide financial and credit market disruptions had a negative impact on us and on the coal industry generally. If any of these conditions return or if there are downturns in economic conditions in our key growth markets, particularly China and India, our business, financial condition or results of operations could be adversely affected. While we are focused on cost control, productivity improvements, increased contributions from our high-margin operations and capital discipline, there can be no assurance that these actions, or any others we may take, will be sufficient in response to downturns in economic and financial conditions.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

Our ability to receive payment for coal sold and delivered or for financially settled contracts depends on the continued creditworthiness of our customers and counterparties. Our customer base has changed with deregulation in the U.S. as utilities have sold their power plants to their non-regulated affiliates or third parties, and with our continued expansion in the Asia-Pacific region. These new customers may have credit ratings that are below investment grade or not rated. If deterioration of the creditworthiness of our customers occurs, our accounts receivable securitization program and our business could be adversely affected.

Risks inherent to mining could increase the cost of operating our business.

Our mining operations are subject to conditions that can impact the safety of our workforce, or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include fires and explosions from methane gas or coal dust; accidental minewater discharges; weather, flooding and natural disasters; unexpected maintenance problems; key equipment failures; variations in coal seam thickness; variations in the amount of rock and soil overlying the coal deposit; variations in rock and other natural materials and variations in geologic conditions. We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, significant mine accidents could occur and have a substantial impact on our results of operations, financial condition or cash flows.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal could suffer.

Transportation costs represent a significant portion of the total cost of coal and the cost of transportation is a critical factor in a customer s purchasing decision. Increases in transportation costs and the lack of sufficient rail and port capacity could lead to reduced coal sales. As of December 31, 2010, certain coal supply agreements permit the customer to terminate the contract if the cost of transportation increases by an amount over specified levels in any given 12-month period.

We depend upon rail, barge, trucking, overland conveyor and ocean-going vessels to deliver coal to markets. While our coal customers typically arrange and pay for transportation of coal from the mine or port to the point of use, disruption of these transportation services because of weather-related problems, infrastructure damage, strikes, lock-outs, lack of fuel or maintenance items, underperformance of the port and rail infrastructure, congestion and balancing systems which are imposed to manage vessel queuing and demurrage, non-performance or delays by co-shippers, transportation delays or other events could temporarily impair our ability to supply coal to our customers and thus could adversely affect our results of operations.

A decrease in the availability or increase in costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires could decrease our anticipated profitability.

Our mining operations require a reliable supply of mining equipment, replacement parts, fuel, explosives, tires, steel-related products (including roof control materials), lubricants and electricity. There has been some consolidation in the supplier base providing mining materials to the coal industry, such as with suppliers of explosives and both surface and underground equipment, that has limited the number of sources for these materials. In situations where we have chosen to concentrate a large portion of purchases with one supplier, it has been to take advantage of cost savings from larger volumes of purchases and to ensure security of supply. If the cost of any of these inputs increased significantly, or if a source for these supplies or mining equipment were unavailable to meet our replacement demands, our profitability could be reduced or we could experience a delay or halt in our production.

An inability of trading, brokerage, mining or freight sources to fulfill the delivery terms of their contracts with us could reduce our profitability.

In conducting our trading, brokerage and mining operations, we utilize third-party sources of coal production and transportation, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. In Australia, the majority of our volume comes from mines that utilize contract miners. Employee relations at mines that use contract miners are the responsibility of the contractor.

Our profitability or exposure to loss on transactions or relationships is dependent upon the reliability (including financial viability) and price of the third-party suppliers, our obligation to supply coal to customers in the event that adverse geologic mining conditions restrict deliveries from our suppliers, our willingness to participate in temporary cost increases experienced by our third-party coal suppliers, our ability to pass on temporary cost increases to our customers, the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market and the ability of our freight sources to fulfill their delivery obligations. Market volatility and price increases for coal or freight on the international and domestic markets could result in non-performance by third-party suppliers under existing contracts with us, in order to take advantage of the higher prices in the current market. Such non-performance could have an adverse impact on our ability to fulfill deliveries under our coal supply agreements.

Our hedging activities may expose us to earnings volatility and other risks.

We enter into hedging arrangements designed primarily to manage market price volatility of foreign currency (primarily the Australian dollar), diesel fuel and explosives. Also, from time to time, we manage the interest rate risk associated with our variable and fixed rate borrowings using interest rate swaps. Generally, we attempt to designate hedging arrangements as cash flow hedges with gains or losses recorded as a separate component of stockholders equity until the hedged transaction occurs (or until hedge ineffectiveness is determined). While we utilize a variety of risk monitoring and mitigation strategies, those strategies require judgment and they cannot anticipate every potential outcome or the timing of such outcomes. As such, there is potential for these hedges to no longer qualify for hedge accounting. If that were to happen, we will be required to recognize the mark to market movements through current year earnings, possibly resulting in increased volatility in our income in future periods. In addition, to the extent that we engage in hedging activities, we may be prevented from realizing the benefits of future price decreases of foreign currency, diesel fuel and explosives.

We also enter into derivative trading instruments, some of which require us to post margin based on the value of those instruments and other credit factors. If our credit is downgraded, the fair value of our hedge positions move significantly, or laws or regulations are passed requiring all hedge arrangements to be exchange-traded or exchange-cleared, we could be required to post additional margin, which could impact our liquidity.

Our ability to operate our company effectively could be impaired if we lose key personnel or fail to attract qualified personnel.

We manage our business with a number of key personnel, the loss of whom could have a material adverse effect on us. In addition, as our business develops and expands, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled and qualified personnel, particularly personnel with mining experience. We cannot provide assurance that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

We could be negatively affected if we fail to maintain satisfactory labor relations.

As of December 31, 2010, we had approximately 7,200 employees, which included approximately 5,100 hourly employees. Approximately 28% of our hourly employees were represented by organized labor unions and generated 9% of 2010 coal production. Additionally, those employed through contract mining relationships in Australia are also members of trade unions. Relations with our employees and, where applicable, organized labor are important to our success. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs. Also, if we fail to maintain good relations with our union workforce, we could experience labor disputes, work stoppages or other disruptions in production that could negatively impact our profitability.

Our mining operations could be adversely affected if we fail to appropriately secure our obligations.

U.S. federal and state laws and Australian laws require us to secure certain of our obligations to reclaim lands used for mining, to pay federal and state workers compensation, to secure coal lease obligations and to satisfy other miscellaneous obligations. The primary methods we use to meet those obligations are to post a corporate guarantee (i.e., self bond), provide a third-party surety bond or provide a letter of credit. As of December 31, 2010, we had $920.3 million of self bonding in place for our reclamation obligations. As of December 31, 2010, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of $1,117.1 million, of which $704.5 million was for post-mining reclamation, $76.1 million related to workers compensation obligations, $110.3 million was for coal lease obligations and $226.2 million was for other obligations, including collateral for surety companies and bank guarantees, road maintenance and performance guarantees. Surety bonds are typically renewable on a yearly basis. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. Letters of credit are subject to us maintaining compliance under our two primary facilities used for such items, which is our unsecured credit facility (Credit Facility) and accounts receivable securitization program. Our failure to retain, or inability to acquire, surety bonds or letters of credit or to provide a suitable alternative would have a material adverse effect on us. That failure could result from a variety of factors including the following:

- lack of availability, higher expense or unfavorable market terms of new surety bonds;
- restrictions on the availability of collateral for current and future third-party surety bond issuers under the terms of our indentures or Credit Facility;
- the exercise by third-party surety bond issuers of their right to refuse to renew the surety; and
- the inability to renew our Credit Facility.

Our ability to self bond reduces our costs of providing financial assurances. To the extent we are unable to maintain our current level of self bonding due to legislative or regulatory changes or changes in our financial condition, our costs would increase.

Our mining operations are extensively regulated, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal.

Federal, state and local authorities regulate the coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. We are required to prepare and present to federal, state and local authorities data pertaining to the effect that any proposed exploration for or production of coal may have upon the environment. The public, including non-governmental organizations, opposition groups and individuals, have statutory rights to comment upon and submit objections to requested permits and approvals. The costs, liabilities and requirements associated with these regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production.

The possibility exists that new legislation and/or regulations and orders related to the environment or employee health and safety may be adopted and may materially adversely affect our mining operations, our cost structure and/or our customers ability to use coal. New legislation or administrative regulations (or new interpretations by the relevant government authorities of existing laws and regulations), including proposals related to the protection of the environment or the reduction of greenhouse gas emissions that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. Some of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser s plant or results in specified increases in the cost of coal or its use. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

A number of laws, including in the U.S. the CERCLA, impose liability relating to contamination by hazardous substances. Such liability may involve the costs of investigating or remediating contamination and damages to natural resources, as well as claims seeking to recover for property damage or personal injury caused by hazardous substances. Such liability may arise from conditions at formerly, as well as currently, owned or operated properties, and at properties to which hazardous substances have been sent for treatment, disposal, or other handling. Liability under CERCLA and similar state statutes is without regard to fault, and typically is joint and several, meaning that a person may be held responsible for more than its share, or even all of, the liability involved. Our mining operations involve some use of hazardous materials. In addition, we have accrued for liability arising out of contamination associated with Gold Fields Mining, LLC (Gold Fields), a dormant, non-coal-producing subsidiary of ours that was previously managed and owned by Hanson PLC, or with Gold Fields former affiliates. Hanson PLC, which is a predecessor owner of ours, transferred ownership of Gold Fields to us in the February 1997 spin-off of its energy business. Gold Fields is currently a defendant in several lawsuits and has received notices of several other potential claims arising out of lead contamination from mining and milling operations it conducted in northeastern Oklahoma. Gold Fields is also involved in investigating or remediating a number of other contaminated sites. See Note 20 to our consolidated financial statements for a description of pending legal proceedings involving Gold Fields.

If the assumptions underlying our asset retirement obligations for reclamation and mine closures are materially inaccurate, our costs could be significantly greater than anticipated.

Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with federal and state reclamation laws in the U.S. and Australia as defined by each mining permit. These obligations are determined for each mine using various estimates and assumptions including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage and the timing of these cash flows, discounted using a credit-adjusted, risk-free rate. Our management and engineers periodically review these estimates. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Moreover, regulatory changes could increase our obligation to perform reclamation and mine closing activities. The resulting estimated asset retirement obligation 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 future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable.

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Moreover, the amount of proven and probable coal reserves described in Item 2. Properties involved the use of certain estimates and those estimates could be inaccurate. Furthermore, we may not be able to mine all of our reserves as profitably as we do at our current operations. Our future success depends upon our conducting successful exploration and development activities or acquiring properties containing economically recoverable reserves. Our current strategy includes increasing our reserves through acquisitions of government and other leases and producing properties and continuing to use our existing properties. The U.S. federal government also leases natural gas and coalbed methane reserves in the West, including in the Powder River Basin. Some of these natural gas and coalbed methane reserves are located on, or adjacent to, some of our Powder River Basin reserves, potentially creating conflicting interests between us and lessees of those interests. Other lessees rights relating to these mineral interests could prevent, delay or increase the cost of developing our coal reserves. These lessees may also seek damages from us based on claims that our coal mining operations impair their interests. Additionally, the U.S. federal government limits the amount of federal land that may be leased by any company to 150,000 acres nationwide. As of

December 31, 2010, we leased a total of 63,657 acres from the federal government. The limit could restrict our ability to lease additional U.S. federal lands.

Our planned mine development projects and acquisition activities may not result in significant additional reserves, and we may not have success developing additional mines. Most of our mining operations are conducted on properties owned or leased by us. Because we do not thoroughly verify title to most of our leased properties and mineral rights until we obtain a permit to mine the property, our right to mine some of our reserves may be materially adversely affected if defects in title or boundaries exist. In addition, in order to develop our reserves, we must also own the rights to the related surface property and receive various governmental permits. We cannot predict whether we will continue to receive the permits necessary for us to operate profitably in the future. We may not be able to negotiate new leases from the government or from private parties, obtain mining contracts for properties containing additional reserves or maintain our leasehold interest in properties on which mining operations have not commenced during the term of the lease. From time to time, we have experienced litigation with lessors of our coal properties and with royalty holders. In addition, from time to time our permit applications have been challenged.

Growth in our global operations increases our risks unique to international mining and trading operations.

We currently have international mining operations in Australia. We have business development, sales and marketing offices in Beijing, China and Jakarta, Indonesia and an international trading group in our Trading and Brokerage segment with offices in London, England, Newcastle, Australia and Singapore. We also have joint venture mining and exploration interests in Venezuela and Mongolia and are exploring other projects that could expand our presence in the Asia-Pacific region. In addition, we are actively pursuing long-term operating, trading and joint-venture opportunities in China, Mongolia, Mozambique, Indonesia and India. The international expansion of our operations increases our exposure to country and currency risks. Some of our international activities include expansion into developing countries where business practices and counterparty reputations may not be as well developed as in our U.S. or Australian operations. We are also challenged by political risks, including the potential for expropriation of assets and limits on the repatriation of earnings. Despite our efforts to mitigate these risks, our results of operations, financial position or cash flow could be adversely affected by these activities.

Risks Associated with Our Indebtedness

We could be adversely affected by the failure of financial institutions to fulfill their commitments under our unsecured credit agreement (the Credit Agreement).

As of December 31, 2010, we had $1.4 billion of available borrowing capacity under our Credit Facility, net of outstanding letters of credit. This committed facility, which matures on June 18, 2015, is provided by a syndicate of financial institutions, with each institution agreeing severally (and not jointly) to make revolving credit loans to us in accordance with the terms of the facility. Although the Credit Facility syndicate consists of over 40 financial institutions, if one or more of these institutions were to default on its obligation to fund its commitment, the portion of the facility provided by such defaulting financial institution would not be available to us.

Our financial performance could be adversely affected by our debt.

As of December 31, 2010, our total indebtedness was $2.8 billion, and we had $1.4 billion of available borrowing capacity under our Credit Facility net of outstanding letters of credit. The indentures governing our Convertible Junior Subordinated Debentures (the Debentures) and 7.375%, 7.875% and 6.5% Senior Notes do not limit the amount of indebtedness that we may issue, and the indenture governing our 5.875% Senior Notes permits the incurrence of additional indebtedness. The degree to which we are leveraged could have important consequences, including, but not limited to:

making it more difficult for us to pay interest and satisfy our debt obligations;

increasing our vulnerability to general adverse economic and industry conditions;

requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal and interest on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, business development, Btu Conversion and clean coal technology projects or other general corporate uses;

limiting our ability to obtain additional financing to fund future working capital, capital expenditures, business development, Btu Conversion and clean coal technology projects or other general corporate requirements;

limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry; and

placing us at a competitive disadvantage compared to less leveraged competitors.

In addition, our debt agreements subject us to financial and other restrictive covenants. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have a material adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. The Credit Agreement and indentures governing certain of our notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to complete those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

The covenants in our Credit Agreement and the indentures governing our Senior Notes and Debentures impose restrictions that may limit our operating and financial flexibility.

Our Credit Agreement, the indentures governing our 7.375%, 7.875%, 6.5% and 5.875% Senior Notes and our Debentures and the instruments governing our other indebtedness contain certain restrictions and covenants which restrict our ability to incur liens and/or debt or provide guarantees in respect of obligations of any other person. Under our Credit Agreement, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined. The financial covenants also place limitations on our investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties and the imposition of liens on our assets.

Operating results below current levels or other adverse factors, including a significant increase in interest rates, could result in our inability to comply with the financial covenants contained in our Credit Agreement. If we violate these covenants and are unable to obtain waivers from our lenders, our debt under our Credit Facility, our 7.375%, 7.875%, 6.5% and 5.875% Senior Notes and our Debentures would be in default and could be accelerated by our lenders. If our indebtedness is accelerated, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or on terms that are acceptable to us. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of our other debt or equity securities and may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

The conversion of our Debentures may result in the dilution of the ownership interests of our existing stockholders.

If the conditions permitting the conversion of our Debentures are met and holders of the Debentures exercise their conversion rights, any conversion value in excess of the principal amount will be delivered in shares of our common stock. If any common stock is issued in connection with a conversion of our

Debentures, our existing stockholders will experience dilution in the voting power of their common stock and earnings per share could be negatively impacted.

Provisions of our Debentures could discourage an acquisition of us by a third-party.

Certain provisions of our Debentures could make it more difficult or more expensive for a third-party to acquire us. Upon the occurrence of certain transactions constituting a change of control as defined in the indenture relating to our Debentures, holders of our Debentures will have the right, at their option, to convert their Debentures and thereby require us to pay the principal amount of such Debentures in cash.

Other Business Risks

Under certain circumstances, we could be responsible for certain federal and state black lung occupational disease liabilities assumed by Patriot in connection with its 2007 spin-off from us.

Patriot is responsible for certain federal and state black lung occupational disease liabilities, which are expected to be less than $150 million, as well as related credit capacity in support of these liabilities. Should Patriot not fund these obligations as they become due, we could be responsible for such costs when incurred.

Our expenditures for postretirement benefit and pension obligations could be materially higher than we have predicted if our underlying assumptions prove to be incorrect.

We provide postretirement health and life insurance benefits to eligible union and non-union employees. We calculated the total accumulated postretirement benefit obligation, which was a liability of $1,031.2 million as of December 31, 2010, $67.3 million of which was a current liability. Net pension liabilities were $109.4 million as of December 31, 2010, $1.8 million of which was a current liability.

These liabilities are actuarially determined and we use various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for these items. Our discount rate is determined by utilizing a hypothetical bond portfolio model which approximates the future cash flows necessary to service our liabilities. We have made assumptions related to future trends for medical care costs in the estimates of retiree health care and work-related injuries and illnesses obligations. Our medical trend assumption is developed by annually examining the historical trend of our cost per claim data. In addition, we make assumptions related to future compensation increases and rates of return on plan assets in the estimates of pension obligations. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Moreover, regulatory changes or changes in medical benefits provided by the government could increase our obligation to satisfy these or additional obligations. In addition, a decrease in the discount rate used to determine pension obligations could result in an increase in the valuation of pension obligations, which could affect the reported funding status of our pension plans and future contributions, as well as the periodic pension cost in subsequent fiscal years.

The decline in the stock market and real estate values in recent years led to a decline in the value of our pension plan assets which required increased contributions in 2009 and 2010. If we experience poor financial performance in asset markets in future years, we may be required to increase contributions further.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, and interest in further regulation, which could significantly affect demand for our products.

Global climate issues continue to attract public and scientific attention. Numerous reports, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of what are commonly referred to as greenhouse gases, including emissions of carbon dioxide from coal combustion by power plants.

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S. or some of its states or by other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources. The potential financial impact on us of future laws or regulations will depend upon the degree to which any such laws or regulations force electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such laws or regulations, the time periods over which those laws or regulations would be phased in and the state of commercial development and deployment of CCS technologies. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws or regulations may have on our results of operations, financial condition or cash flows.

As we continue to pursue Btu Conversion and clean coal technology activities, we face challenges and risks that differ from others in the mining business.

We continue to pursue opportunities to participate in technologies to economically convert a portion of our coal resources to natural gas and liquids such as diesel fuel, gasoline and jet fuel (Btu Conversion). We are also promoting the development of clean coal technologies that would reduce the emissions from the use of coal, and/or capture and store the emissions from the use of coal. As we move forward with these projects, we are exposed to risks related to the performance of our partners, securing required financing, obtaining necessary permits, meeting stringent regulatory laws, maintaining strong supplier relationships and managing (along with our partners) large projects, including managing through long lead times for ordering and obtaining capital equipment. Our work in new or recently commercialized technologies could expose us to unanticipated risks, evolving legislation and uncertainty regarding the extent of future government support and funding.

Our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt.

Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it more difficult for a third-party to acquire us, even if doing so might be beneficial to our stockholders. Provisions of our by-laws and certificate of incorporation impose various procedural and other requirements that could make it more difficult for stockholders to effect certain corporate actions. For example, a change in control of our Company may be delayed or deterred as a result of the stockholders rights plan adopted by our Board of Directors. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock and may have the effect of delaying or preventing a change in control.

Diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results.

The mining industry has limited industry-specific accounting literature and, as a result, we understand diversity in practice exists in the interpretation and application of accounting literature to mining specific issues. As diversity in mining industry accounting is addressed, we may need to restate our reported results if the resulting interpretations differ from our current accounting practices.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Coal Reserves

We had an estimated 9.0 billion tons of proven and probable coal reserves as of December 31, 2010. An estimated 7.8 billion tons of our proven and probable coal reserves are in the U.S. and 1.2 billion tons are in Australia. 28% of our Australian proven and probable coal reserves, or 336 million tons, are metallurgical coal with the remainder being thermal coal. 45% of our reserves, or 4.0 billion tons, are compliance coal and 55% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). We own approximately 41% of these reserves and lease property containing the remaining 59%. Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2

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pounds or less per million Btu. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emission allowance credits or blending higher sulfur coal with lower sulfur coal.

Below is a table summarizing the locations and reserves of our major operating regions.

		Proven and Probable Reserves as of December 31, 2010[1]		
Operating Regions	**Locations**	**Owned Tons**	**Leased Tons**	**Total Tons**
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	2,749	901	3,650
Powder River Basin	Wyoming and Montana	67	2,805	2,872
Southwest	Arizona and New Mexico	792	284	1,076
Colorado	Colorado	44	186	230
Total United States		3,652	4,176	7,828
Australia	New South Wales		418	418
Australia	Queensland		767	767
Total Australia			1,185	1,185
Total Proven and Probable Coal Reserves		3,652	5,361	9,013

(1) Reserves have been adjusted to take into account estimated losses involved in producing a saleable product.

Reserves are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) 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 close and the geographic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable (Indicated) Reserves Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our estimates of proven and probable coal reserves are established within these guidelines. Proven reserves require the coal to lie within one-quarter mile of a valid point of measure or point of observation, such as exploratory drill holes or previously mined areas. Estimates of probable reserves may lie more than one-quarter mile, but less than three-quarters of a mile, from a point of thickness measurement. Estimates within the proven category have the highest degree of assurance, while estimates within the probable category have only a moderate degree of geologic assurance. Further exploration is necessary to place probable reserves into the proven reserve category. Our active properties generally have a much higher degree of reliability because of increased drilling density. Active surface reserves generally have points of observation as close as 330 feet to 660 feet.

Our reserve estimates are prepared by our staff of experienced geologists. We also have a chief geologist of reserve reporting whose primary responsibility is to track changes in reserve estimates, supervise our other geologists and coordinate periodic third-party reviews of our reserve estimates by qualified mining consultants.

Our reserve estimates are predicated on information obtained from our ongoing drilling program, which totals nearly 500,000 individual drill holes. We compile data from individual drill holes in a computerized drill-hole database from which the depth, thickness and, where core drilling is used, the quality of the coal is determined. The density of the drill pattern determines whether the reserves will be classified as proven or probable. The reserve estimates are then input into our computerized land management system, which overlays the geological data with data on ownership or control of the mineral and surface interests to determine the extent of our reserves in a given area. The land management system contains reserve information, including the quantity and quality (where available) of reserves as well as production rates, surface ownership, lease payments and other information relating to our coal reserves and land holdings. We periodically update our reserve estimates to reflect production of coal from the reserves and new drilling or other data received. Accordingly, reserve estimates will change from time to time to reflect mining activities, analysis of new engineering and geological data, changes in reserve holdings, modification of mining methods and other factors.

Our estimate of the economic recoverability of our reserves is based upon a comparison of unassigned reserves to assigned reserves currently in production in the same geologic setting to determine an estimated mining cost. These estimated mining costs are compared to expected market prices for the quality of coal expected to be mined and taking into consideration typical contractual sales agreements for the region and product. Where possible, we also review production by competitors in similar mining areas. Only reserves expected to be mined economically are included in our reserve estimates. Finally, our reserve estimates include reductions for recoverability factors to estimate a saleable product.

We periodically engage independent mining and geological consultants and consider their input regarding the procedures used by us to prepare our internal estimates of coal reserves, selected property reserve estimates and tabulation of reserve groups according to standard classifications of reliability.

With respect to the accuracy of our reserve estimates, our experience is that recovered reserves are within plus or minus 10% of our proven and probable estimates, on average, and our probable estimates are generally within the same statistical degree of accuracy when the necessary drilling is completed to move reserves from the probable to the proven classification.

We have numerous U.S. federal coal leases that are administered by the U.S. Department of the Interior under the Federal Coal Leasing Amendments Act of 1976. These leases cover our principal reserves in Wyoming and other reserves in Montana and Colorado. Each of these leases continues indefinitely, provided there is diligent development of the property and continued operation of the related mine or mines. The Bureau of Land Management has asserted the right to adjust the terms and conditions of these leases, including rent and royalties, after the first 20 years of their term and at 10-year intervals thereafter. Annual rents on surface land under our federal coal leases are now set at $3.00 per acre. Production royalties on federal leases are set by statute at 12.5% of the gross proceeds of coal mined and sold for surface-mined coal and 8% for underground-mined coal. The U.S. federal government limits by statute the amount of federal land that may be leased by any company and its affiliates at any time to 75,000 acres in any one state and 150,000 acres nationwide. As of December 31, 2010, we leased 11,328 acres of federal land in Colorado, 11,254 acres in Montana and 41,075 acres in Wyoming, for a total of 63,657 nationwide.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 64,783 acres of land in northern Arizona lying within the boundaries of the Navajo Nation and Hopi Indian reservations. We also lease coal-mining properties from various state governments in the U.S.

Private U.S. coal leases normally have terms of between 10 and 20 years and usually give us the right to renew the lease for a stated period or to maintain the lease in force until the exhaustion of mineable and merchantable coal contained on the relevant site. These private U.S. leases provide for royalties to be paid to the lessor either as a fixed amount per ton or as a percentage of the sales price. Many U.S. leases also require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments. The terms of our private U.S. leases are normally extended by active production at or near the end of the lease term. U.S. leases containing undeveloped reserves may expire or these leases may be renewed periodically.

Mining and exploration in Australia is generally carried on under leases or licenses granted by state governments. Mining leases are typically for an initial term of up to 21 years (but which may be renewed) and contain conditions relating to such matters as minimum annual expenditures, restoration and rehabilitation. Royalties are paid to the state government as a percentage of the sales price. Generally landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by state governments. Compensation is payable to landowners for loss of access to the land, and the amount of compensation can be determined by agreement or arbitration. Surface rights are typically acquired directly from landowners and, in the absence of agreement, there is an arbitration provision in the mining law.

Consistent with industry practice, we conduct only limited investigation of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased properties are not completely verified until we prepare to mine those reserves.

With a portfolio of approximately 9.0 billion tons, we believe that we have sufficient reserves to replace capacity from depleting mines for the foreseeable future and that our significant reserve holdings is one of our strengths. We believe that the current level of production at our major mines is sustainable for the foreseeable future.

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The following chart provides a summary, by mining complex, of production for the years ended December 31, 2010, 2009 and 2008, tonnage of coal reserves that is assigned to our operating mines, our property interest in those reserves and other characteristics of the facilities.

PRODUCTION AND ASSIGNED RESERVES (1)
(Tons in Millions)

	Production				Sulfur Content(2)					As of Decemb	
ining Complex	Year Ended Dec. 31, 2010	Year Ended Dec. 31, 2009	Year Ended Dec. 31, 2008	Type of Coal	<1.2 lbs. sulfur dioxide per Million Btu	>1.2 to 2.5 lbs. sulfur dioxide per Million Btu	>2.5 lbs. sulfur dioxide per Million Btu	As Received Btu per pound(3)	Assigned Proven and Probable Reserves	Owned	Leas
	3.4	3.3	3.5	Thermal			9	11,200	9	7	
	3.2	3.3	3.2	Thermal			15	11,000	15	14	
	2.9	3.4	3.6	Thermal			25	12,100	25	16	
	2.8			Thermal	6	26	227	11,500	259	135	1
	2.7	2.0	1.5	Thermal			43	11,300	43	8	
	2.1	0.7	0.7	Thermal			23	12,300	23	15	
	2.0	2.0	2.2	Thermal			3	10,600	3	3	
	1.7	2.0	1.9	Thermal				NA			
	1.7	1.8	2.2	Thermal			3	11,100	3	3	
2010)	1.5	3.5	3.4	Thermal				NA			
	1.5	1.6	1.6	Thermal			5	11,500	5		
	1.1	1.6	1.9	Thermal	22	2	33	11,300	57	4	
und	0.8	2.1	2.2	Thermal			19	12,200	19	13	
	0.1			Thermal			17	11,000	17	13	
ed in 2009)		1.4	1.9	Thermal				NA			
	27.5	28.7	29.8		28	28	422		478	231	2
e	105.8	98.3	97.6	Thermal	1,184		33	8,700	1,217		1,2
	23.5	23.3	31.2	Thermal	669	130	23	8,200	822		8
	11.2	15.8	18.4	Thermal	293	72	4	8,300	369		3
	140.5	137.4	147.2		2,146	202	60		2,408		2,4
	7.8	7.5	8.0	Thermal	169	76	3	10,600	248		2
	6.6	5.1	3.3	Thermal	24	83	65	9,000	172	157	
	1.6	1.8	3.3	Thermal	18	114	13	9,300	145	124	

	16.0	14.4	14.6		211	273	81		565	281	2
	7.7	7.8	8.0	Thermal	44			11,200	44	8	
	9.6	8.4	7.5	Thermal		197		11,200	197		1
	6.6	4.1	5.4	Thermal/Met.	178			12,200	178		1
efield	3.2	2.5	2.8	Met.	114			12,900	114		1
	2.5	2.0	2.6	Thermal/Met.	45			12,700	45		
	1.6	1.5	1.5	Met.	43			12,600	43		
	1.6	2.3	2.6	Thermal	337			10,800	337		3
	1.6	0.9	1.2	Met.	46			12,600	46		
	26.7	21.7	23.6		763	197			960		9
tions	218.4	210.0	223.2		3,192	700	563		4,455	520	3,9
s		0.8	2.0								
	218.4	**210.8**	**225.2**		**3,192**	**700**	**563**		**4,455**	**520**	**3,9**

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The following chart provides a summary of the amount of our proven and probable coal reserves in each U.S. state and Australia state, the predominant type of coal mined in the applicable location, our property interest in the reserves and other characteristics of the facilities.

ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES AS OF DECEMBER 31, 2010

(Tons in Millions)

Total Tons		Proven and Probable			Type of	Sulfur Content[(2)]			As	Reserve Control	
Assigned	**Unassigned**	**Reserves**	**Proven**	**Probable**	**Coal**	**<1.2 lbs. sulfur dioxide per Million Btu**	**>1.2 to 2.5 lbs. sulfur dioxide per Million Btu**	**>2.5 lbs. sulfur dioxide per Million Btu**	**Received Btu per pound[(3)]**	**Owned**	**Leased**
82	2,266	2,348	1,208	1,140	Thermal			2,348	10,900	1,973	375
396	403	799	591	208	Thermal	27	38	734	11,400	472	327
	503	503	265	238	Thermal			503	11,900	304	199
478	3,172	3,650	2,064	1,586		27	38	3,585		2,749	901
	161	161	157	4	Thermal	9	121	31	8,500	67	94
2,408	303	2,711	2,668	43	Thermal	2,450	202	59	8,500		2,711
2,408	464	2,872	2,825	47		2,459	323	90		67	2,805
248		248	248		Thermal	169	76	3	10,600		248
317	511	828	750	78	Thermal	156	402	270	8,700	792	36
565	511	1,076	998	78		325	478	273		792	284
44	186	230	146	84	Thermal	227		3	10,700	44	186
418		418	335	83	Thermal/Met.	221	197		11,800		418
542	225	767	576	191	Thermal/Met.	767			11,600		767
960	225	1,185	911	274		988	197				1,185
4,455	4,558	9,013	6,944	2,069		4,026	1,036	3,951		3,652	5,361

(1) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2010. Unassigned reserves represent coal at currently non-producing locations that would require new mine development, mining equipment or plant facilities before operations could begin on the property.

(2) Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Non-compliance coal is defined as coal having sulfur dioxide content in excess of this standard. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emissions allowance credits or blending higher sulfur coal with lower sulfur coal.

(3) As-received Btu per pound includes the weight of moisture in the coal on an as sold basis. The range of variability of the moisture content in coal across a given region may affect the actual shipped Btu content of current production from assigned reserves.

(4) Wambo includes the Wambo Open-Cut Mine and the North Wambo Underground Mine. The North Wambo Underground Mine produces both thermal and pulverized coal injection, or PCI metallurgical coal.

(5) Proven and probable coal reserves for our Burton Mine reflects our 95% proportional ownership and consolidation.

Item 3. *Legal Proceedings.*

See Note 20 to our consolidated financial statements for a description of our pending legal proceedings, which is incorporated herein by reference.

Item 4. *[Removed and Reserved]*

Executive Officers of the Company

Set forth below are the names, ages as of February 18, 2011 and current positions of our executive officers. Executive officers are appointed by, and hold office at the discretion of, our Board of Directors, subject to the terms of any employment agreements.

Name	Age	Position
Gregory H. Boyce	56	Chairman and Chief Executive Officer, Director
Richard A. Navarre	50	President and Chief Commercial Officer
Michael C. Crews	43	Executive Vice President and Chief Financial Officer
Sharon D. Fiehler	54	Executive Vice President and Chief Administrative Officer
Eric Ford	56	Executive Vice President and Chief Operating Officer
Alexander C. Schoch	56	Executive Vice President Law, Chief Legal Officer and Secretary

Gregory H. Boyce was elected Chairman of the Board on October 10, 2007 and has been a director of the Company since March 2005. He was named Chief Executive Officer Elect in March 2005, and assumed the position of Chief Executive Officer in January 2006. Mr. Boyce served as our President from October 2003 to December 2007 and as our Chief Operating Officer from October 2003 to December 2005. He previously served as Chief Executive   Energy of Rio Tinto plc (an international natural resource company) from 2000 to 2003. Other prior positions include President and Chief Executive Officer of Kennecott Energy Company from 1994 to 1999 and President of Kennecott Minerals Company from 1993 to 1994. He has extensive engineering and operating experience with Kennecott and also served as Executive Assistant to the Vice Chairman of Standard Oil of Ohio from 1983 to 1984. Mr. Boyce serves on the board of directors of Marathon Oil Corporation. He is Chairman of the National Mining Association and a member of the World

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Coal Association, the National Coal Council and the Coal Industry Advisory Board of the International Energy Agency. He is a Board member of the Business Roundtable and the American Coalition for Clean Coal Electricity. He is a member of the Business Council; Civic Progress in St. Louis; the Board of Trustees of St. Louis Children s Hospital; the Board of Trustees of Washington University in St. Louis; and the Advisory Council of the University of Arizona s Department of Mining and Geological Engineering.

Richard A. Navarre is our President and Chief Commercial Officer. He previously served as our Executive Vice President of Corporate Development and Chief Financial Officer from July 2006 to January 2008 and as Chief Financial Officer from October 1999 to June 2008. Mr. Navarre is a member of the Hall of Fame of the College of Business at Southern Illinois University Carbondale; a member of the Board of Advisors of the College of Business and Administration and the School of Accountancy of Southern Illinois University Carbondale; a member of the International Business Advisory Board of the University of Missouri St. Louis; and a member of the Board of Directors of the Regional Chamber and Growth Association of St. Louis. He is a Director of the United Way of Greater St. Louis; Treasurer of the Missouri Historical Society; a member of Financial Executives International; Fellow, Foreign Policy Association; and a former chairman of the Bituminous Coal Operators Association.

Michael C. Crews was named our Executive Vice President and Chief Financial Officer in June 2008. He joined us in 1998 as Senior Manager of Financial Reporting, and has served as Assistant Corporate Controller, Director of Planning, Assistant Treasurer, Vice President of Planning, Analysis, and Performance Assessment, and Vice President of Operations Planning. Prior to joining us, Mr. Crews served for three years in financial positions with MEMC Electronic Materials, Inc. and six years at KPMG Peat Marwick in St. Louis. He serves on the Board of Directors of Action for Autism in St. Louis. Mr. Crews has a Bachelor of Science degree in Accountancy from the University of Missouri at Columbia and a Master of Business Administration (MBA) degree from Washington University in St. Louis.

Sharon D. Fiehler has been our Executive Vice President and Chief Administrative Officer since January 2008. From April 2002 to January 2008, she served as our Executive Vice President of Human Resources and Administration. Ms. Fiehler joined us in 1981 as Manager Salary Administration and has held a series of employee relations, compensation and salaried benefits positions. She holds degrees in social work and psychology and a MBA, and prior to joining us was a personnel representative for Ford Motor Company. Ms. Fiehler is a Director of the Federal Reserve Bank of St. Louis; a member of the Board of Trustees of the Missouri Botanical Garden; Chair of the Board of Directors of Junior Achievement of Mississippi Valley, Inc.; a member of the Board of Directors of the St. Louis Zoo Association; and President of the Chancellor s Council of the University of Missouri St. Louis. She was a recipient of the 2006 St. Louis Business Journal Most Influential Women Award, the 2008 YWCA Leader of Distinction Award and the 2010 Logos School St. Louis Women of Distinction Award. She is also a member of the Missouri Women s Forum and the St. Louis Forum.

Eric Ford was named our Executive Vice President and Chief Operating Officer in March 2007. Mr. Ford has 39 years of extensive international management, operating and engineering experience and most recently served as Chief Executive Officer of Anglo Coal Australia Pty Ltd. He joined Anglo Coal in 1971 and, after a series of increasingly complex operating assignments, was appointed President and Chief Executive Officer of Anglo American s joint venture coal mining operation in Colombia in 1998. In 2000, he returned to Anglo American Corporation as Executive Director of Operations for Anglo Platinum Corporation Limited. He was subsequently appointed Chief Executive Officer of Anglo Coal Australia Pty Ltd in 2001. Mr. Ford holds a Master of Science degree in Management Science from Imperial College in London and a Bachelor of Science degree in Mining Engineering (cum laude) from the University of the Witwatersrand in Johannesburg, South Africa. He was previously Deputy Chairman and a member of the Executive Committee of the Coal Industry Advisory Board of the International Energy Agency, and Vice Chairman and Director of the Minerals Council of Australia.

Alexander C. Schoch was named our Executive Vice President Law and Chief Legal Officer in October 2006 and our Secretary in May 2008. Prior to joining us, Mr. Schoch served as Vice President and General Counsel for Emerson Process Management, an operating segment of Emerson Electric Co. and a leading supplier of process-automation products, from August 2004 to October 2006. Mr. Schoch also served in several legal positions with Goodrich Corporation, a global supplier to the aerospace and defense industries, from 1987 to 2004, including Vice President, Associate General Counsel and Secretary. Prior to that, he worked for Marathon Oil Company as an attorney in its international exploration and production division. Mr. Schoch holds a Juris Doctorate from Case Western Reserve University in Ohio, as well as a Bachelor of Arts in Economics from Kenyon College in Ohio. He is admitted to practice law in several states, and is a member of the American and International Bar Associations. Mr. Schoch serves as a Trustee at Large on the Board of Trustees for the Energy & Mineral Law Foundation and on the Board of Directors of North Side Community School in St. Louis, Missouri.

PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our common stock is listed on the New York Stock Exchange, under the symbol BTU . As of February 11, 2011, there were 1,307 holders of record of our common stock.

The table below sets forth the range of quarterly high and low sales prices (including intraday prices) for our common stock on the New York Stock Exchange during the calendar quarters indicated.

	Share Price		Dividends
	High	**Low**	**Paid**
2010			
First Quarter	$ 52.14	$ 39.88	$ 0.070
Second Quarter	50.25	34.89	0.070
Third Quarter	49.94	38.08	0.070
Fourth Quarter	64.59	48.76	0.085
2009			
First Quarter	$ 30.95	$ 20.17	$ 0.060
Second Quarter	37.44	23.56	0.060
Third Quarter	41.54	27.19	0.060
Fourth Quarter	48.21	34.54	0.070

Dividend Policy

We have declared and paid quarterly dividends since our initial public offering in 2001. Most recently, our Board of Directors declared a dividend of $0.085 per share of Common Stock on January 27, 2011, payable on March 3, 2011, to stockholders of record on February 10, 2011. The declaration and payment of dividends and the amount of dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors. Limitations on our ability to pay dividends imposed by our debt instruments are discussed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Share Repurchases

On October 24, 2008, we announced that our Board of Directors authorized a share repurchase program of up to $1 billion of the then outstanding shares of our common stock. The repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. Our Chairman and Chief Executive Officer also has the authority to direct us to repurchase up to $100 million of our common stock outside the share repurchase program. The repurchase program does not have an expiration date and may be discontinued at any time. Through

December 31, 2010, we have made repurchases of 7.7 million shares at a cost of $299.6 million ($199.8 million and $99.8 million in 2008 and 2006, respectively), leaving $700.4 million available for share repurchases under the program.

The following table summarizes all share repurchases for the three months ended December 31, 2010:

Period	Total Number of Shares Purchased[(1)]	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Dollar Value that May Yet Be Used to Repurchase Shares Under the Publicly Announced Program (In millions)
October 1 through October 31, 2010	1,392	$ 50.53		$ 700.4
November 1 through November 30, 2010	11,122	53.91		700.4
December 1 through December 31, 2010	70,087	63.98		700.4
Total	82,601	$ 62.40		

(1) Represents shares withheld to cover the withholding taxes upon the vesting of restricted stock, which are not a part of the share repurchase program.

Item 6. *Selected Financial Data.*

The following table presents selected financial and other data about us for the most recent five fiscal years. The following table and the discussion of our results of operations in 2010, 2009 and 2008 in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations includes references to, and analysis of, our Adjusted EBITDA results. We define Adjusted EBITDA as income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expense and depreciation, depletion and amortization. Adjusted EBITDA is used by management to measure our segments operating performance, and management also believes it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Because Adjusted EBITDA is not calculated identically by all companies, our calculation may not be comparable to similarly titled measures of other companies. Adjusted EBITDA is reconciled to its most comparable measure, under U.S. generally accepted accounting principles (GAAP), as reflected at the end of Item 6. Selected Financial Data and in Note 22 to our consolidated financial statements.

The selected financial data for all periods presented reflect the assets, liabilities and results of operations from subsidiaries spun off as Patriot as discontinued operations. We also have classified as discontinued operations those operations recently divested, as well as certain non-strategic mining assets held for sale where we have committed to the divestiture of such assets.

In October 2006, we acquired Excel Coal Limited (Excel). Our results of operations include Excel s results of operations from the date of acquisition.

We have derived the selected historical financial data as of and for the years ended December 31, 2010, 2009, 2008, 2007 and 2006 from our audited financial statements. You should read the following table in

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conjunction with the financial statements, the related notes to those financial statements and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

The results of operations for the historical periods included in the following table are not necessarily indicative of the results to be expected for future periods. In addition, the Risk Factors section of Item 1A. Risk Factors of this report includes a discussion of risk factors that could impact our future results of operations.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	$ 6,860.0	$ 6,012.4	$ 6,561.0	$ 4,523.8	$ 4,045.6
Costs and expenses	5,534.3	5,167.6	5,164.7	3,924.1	3,432.8
Operating profit	1,325.7	844.8	1,396.3	599.7	612.8
Interest expense, net	212.5	193.1	217.0	228.8	127.8
Income from continuing operations before income taxes	1,113.2	651.7	1,179.3	370.9	485.0
Income tax provision (benefit)	308.1	193.8	191.4	(70.7)	(85.6)
Income from continuing operations, net of income taxes	805.1	457.9	987.9	441.6	570.6
Income (loss) from discontinued operations, net of income taxes	(2.9)	5.1	(28.8)	(180.1)	30.7
Net income	802.2	463.0	959.1	261.5	601.3
Less: net income (loss) attributable to noncontrolling interests	28.2	14.8	6.2	(2.3)	0.6
Net income attributable to common stockholders	$ 774.0	$ 448.2	$ 952.9	$ 263.8	$ 600.7
Basic earnings per share from continuing operations	$ 2.89	$ 1.66	$ 3.63	$ 1.67	$ 2.15
Diluted earnings per share from continuing operations	$ 2.86	$ 1.64	$ 3.60	$ 1.64	$ 2.11
Weighted average shares used in calculating basic earnings per share	267.0	265.5	268.9	264.1	263.4
Weighted average shares used in calculating diluted earnings per share	269.9	267.5	270.7	268.6	268.8
Dividends declared per share	$ 0.295	$ 0.250	$ 0.240	$ 0.240	$ 0.240
Other Data					
Tons sold	245.9	243.6	255.0	235.5	221.2
Net cash provided by (used in) continuing operations:					
Operating activities	$ 1,103.7	$ 1,055.8	$ 1,420.8	$ 465.0	$ 611.1

Investing activities	(703.6)	(408.2)	(419.3)	(538.9)	(2,055.6)
Financing activities	(77.1)	(104.6)	(498.0)	37.4	1,403.0
Adjusted EBITDA	1,815.1	1,290.1	1,846.9	969.7	909.7
Balance Sheet Data (at period end)					
Total assets	$ 11,363.1	$ 9,955.3	$ 9,695.6	$ 9,082.3	$ 9,504.7
Total long-term debt (including capital leases)	2,750.0	2,752.3	2,793.6	2,909.0	2,911.6
Total stockholders equity	4,689.3	3,755.9	3,119.5	2,735.3	2,587.0

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Adjusted EBITDA is calculated as follows (unaudited):

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(Dollars in millions)				
Income from continuing operations, net of income taxes	$ 805.1	$ 457.9	$ 987.9	$ 441.6	$ 570.6
Income tax provision (benefit)	308.1	193.8	191.4	(70.7)	(85.6)
Depreciation, depletion and amortization	440.9	405.2	402.4	346.3	282.7
Asset retirement obligation expense	48.5	40.1	48.2	23.7	14.2
Interest expense, net	212.5	193.1	217.0	228.8	127.8
Adjusted EBITDA	$ 1,815.1	$ 1,290.1	$ 1,846.9	$ 969.7	$ 909.7

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

Overview

We are the world s largest private sector coal company, with majority interests in 28 coal mining operations in the U.S. and Australia. In 2010, we produced 218.4 million tons of coal and sold 245.9 million tons of coal.

We conduct business through four principal segments: Western U.S. Mining, Midwestern U.S. Mining, Australian Mining and Trading and Brokerage. The principal business of the Western and Midwestern U.S. Mining segments is the mining, preparation and sale of thermal coal, sold primarily to electric utilities. Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado operations. Our Midwestern U.S. Mining operations consist of our Illinois and Indiana operations. The business of our Australian Mining Segment is the mining of various qualities of low-sulfur, high Btu coal (metallurgical coal) as well as thermal coal primarily sold to an international customer base with a portion sold to Australian steel producers and power generators. Metallurgical coal is produced primarily from five of our Australian mines.

In the U.S., we typically sell coal to utility customers under long-term contracts (those with terms longer than one year). In Australia, our production is sold primarily into the export metallurgical and thermal markets with an increasing number of the contracts negotiated with our customers on a quarterly basis. During 2010, approximately 91% of our worldwide sales (by volume) were under long-term contracts. For the year ended December 31, 2010, 84% of our total sales (by volume) were to U.S. electricity generators, 14% were to customers outside the U.S. and 2% were to the U.S. industrial sector.

Our Trading and Brokerage segment s principal business is the brokering of coal sales of other producers both as principal and agent, and the trading of coal, freight and freight-related contracts. We also provide transportation-related services in support of our coal trading strategy, as well as hedging activities in support of our mining operations.

Our fifth segment, Corporate and Other, includes mining and export/transportation joint ventures, energy-related commercial activities, as well as the management of our vast coal reserve and real estate holdings.

We continue to pursue Btu Conversion projects that expand the uses of coal through CTL and CTG. Our participation in generation development projects involves using our surface lands and coal reserves as the basis for mine-mouth plants, such as with our involvement in Prairie State. We are also advancing several initiatives associated with clean coal technologies, including CCS.

As discussed more fully in Item 1A. Risk Factors, our results of operations in the near-term could be negatively impacted by adverse weather conditions, availability of transportation for coal shipments, unforeseen geologic conditions or equipment problems at mining locations and by the rate of the economic recovery. On a long-term basis, our results of operations could be impacted by our ability to secure or acquire high-quality coal reserves, find replacement buyers for coal under contracts with comparable terms to existing contracts or the passage of new or expanded regulations that could limit our ability to mine, increase our

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mining costs or limit our customers ability to utilize coal as fuel for electricity generation. In the past, we have achieved production levels that are relatively consistent with our projections. We may adjust our production levels further in response to changes in market demand.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Summary

In the U.S., demand for coal rose approximately 75 million tons in 2010, led by a 5.5% increase in coal-fueled generation and an 18 million ton rise in exports. The international coal markets strengthened in 2010 due to strong Asian demand growth and weather-related generation recovery in the Atlantic markets, coupled with supply challenges across the major coal exporting nations of the Southern Hemisphere. Our analyses of general business conditions indicate the following:

- Seaborne coal demand increased an estimated 13% in 2010, led by a 32% recovery in global metallurgical coal demand;
- Pacific thermal coal demand for electricity generation rose 15% in 2010, while the Atlantic market declined 10%;
- Benchmark pricing of high quality, hard coking coal in the seaborne market has ranged between $200 to $225 per tonne since April 2010;
- The benchmark prompt seaborne thermal coal price in Newcastle, Australia rose 34% in 2010;
- U.S. coal generation accounted for nearly two-thirds of the growth in total power output in 2010 due to new coal-fueled generation, favorable weather, and a partial reversal of 2009 s coal-to-gas switching; and
- Indexed U.S. coal prices rose in 2010 in all regions, with increases ranging from 30 to 50%.

Our revenues increased compared to the prior year by $847.6 million and Segment Adjusted EBITDA increased over the prior year by $535.2 million, led by higher Australian pricing and sales volumes in the current year despite unfavorable weather-related volume impacts that occurred late in 2010.

Income from continuing operations, net of income taxes, increased compared to the prior year by $347.2 million due to the increase in Segment Adjusted EBITDA discussed above, partially offset by increased income taxes, decreased Corporate and Other Adjusted EBITDA, and increased depreciation, depletion and amortization and interest expense.

We ended the year with total available liquidity of $2.7 billion, as discussed further in Liquidity and Capital Resources.

Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2010 and 2009:

	Year Ended December 31,		Increase (Decrease)	
	2010	2009	Tons	%

	(Tons in millions)			
Western U.S. Mining	163.8	160.1	3.7	2.3%
Midwestern U.S. Mining	29.7	31.8	(2.1)	(6.6)%
Australian Mining	27.0	22.3	4.7	21.1%
Trading and Brokerage	25.4	29.4	(4.0)	(13.6)%
Total tons sold	245.9	243.6	2.3	0.9%

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Revenues

The following table presents revenues for the years ended December 31, 2010 and 2009:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2010	2009	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 2,706.3	$ 2,612.6	$ 93.7	3.6%
Midwestern U.S. Mining	1,320.6	1,303.8	16.8	1.3%
Australian Mining	2,520.0	1,678.0	842.0	50.2%
Trading and Brokerage	291.1	391.0	(99.9)	(25.5)%
Corporate and Other	22.0	27.0	(5.0)	(18.5)%
Total revenues	$ 6,860.0	$ 6,012.4	$ 847.6	14.1%

The increase in Australian Mining operations revenues was driven by a higher weighted average sales price of 23.9%, led by increased pricing on seaborne metallurgical and thermal coals and a higher mix of metallurgical coal shipments. Volumes also increased in the current year (21.1%) driven by increased demand for metallurgical coal (metallurgical coal shipments of 9.8 million tons were 2.9 million tons, or 42%, greater than the prior year). These increases were muted to an extent by the flooding in Queensland in late 2010 that negatively impacted our production and also restricted throughput due to damage to the port and rail systems. The metallurgical coal demand increase reflects the strengthening of the coal markets as discussed above, coupled with prior year customer destocking of inventory and lower capacity utilization at steel customers.

Western U.S. Mining operations revenues increased compared to the prior year due to increased sales volume (2.3%) driven by our Powder River Basin and Southwest regions due to increased customer demand and a higher weighted average sales price of 1.3%.

In the Midwestern U.S. Mining segment, revenue improvements due to an increase in our weighted average sales price of 8.4% from contractual price increases were largely offset by decreased shipments (6.6%) on lower customer demand.

Trading and Brokerage revenues were down primarily due to lower international brokerage revenues, unfavorable market movements on freight positions that support our export volumes and weather related shipment deferrals.

Segment Adjusted EBITDA

The following table presents segment Adjusted EBITDA for the years ended December 31, 2010 and 2009:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2010	2009	$	%

	(Dollars in millions)			
Western U.S. Mining	$ 816.7	$ 721.5	$ 95.2	13.2%
Midwestern U.S. Mining	322.1	281.9	40.2	14.3%
Australian Mining	953.8	437.8	516.0	117.9%
Trading and Brokerage	77.2	193.4	(116.2)	(60.1)%
Total Segment Adjusted EBITDA	$ 2,169.8	$ 1,634.6	$ 535.2	32.7%

Our Australian Mining segment benefitted from a higher weighted average sales price ($413.0 million) and increased volumes ($127.9 million) as discussed above, and productivity improvements at our North Goonyella and Wambo underground mines along with fewer longwall move days in the current year ($116.0 million). Partially offsetting the above improvements were net higher adverse weather impacts

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($47.0 million) driven by the flooding in late 2010, unfavorable foreign currency impact on operating costs, net of hedging ($34.5 million), increased royalty expense associated with our higher-priced metallurgical coal shipments ($31.7 million) and increased demurrage costs ($10.7 million).

Western U.S. Mining operations Adjusted EBITDA increased compared to the prior year due to the higher volumes ($49.8 million) and a higher weighted average sales price ($42.1 million) discussed above, lower repairs and maintenance costs due to timing of repairs and improved equipment efficiency ($35.0 million) and fewer longwall move days at our Twentymile Mine in the current year ($10.0 million), partially offset by prior year customer contract termination and restructuring agreements ($27.8 million) and increased commodity costs in the current year ($20.8 million).

In the Midwestern U.S. Mining segment, a higher weighted average sales price ($98.5 million), as discussed above, was partially offset by lower volumes ($42.3 million) due to decreased demand and increased costs on lower productivity due to compliance measures and geological conditions at certain underground mines.

Our Trading and Brokerage segment was down primarily due to the lower revenues as discussed above.

Income From Continuing Operations Before Income Taxes

The following table presents income from continuing operations before income taxes for the years ended December 31, 2010 and 2009:

	Year Ended December 31,		Increase (Decrease) to Income	
	2010	**2009**	**$**	**%**
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 2,169.8	$ 1,634.6	$ 535.2	32.7%
Corporate and Other Adjusted EBITDA[1]	(354.7)	(344.5)	(10.2)	(3.0)%
Depreciation, depletion and amortization	(440.9)	(405.2)	(35.7)	(8.8)%
Asset retirement obligation expense	(48.5)	(40.1)	(8.4)	(20.9)%
Interest expense	(222.1)	(201.2)	(20.9)	(10.4)%
Interest income	9.6	8.1	1.5	18.5%