PEABODY ENERGY CORP
Form 10-K
February 24, 2010

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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, 2009

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

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, 2009: Common Stock, par value $0.01 per share, $8.1 billion.

Number of shares outstanding of each of the Registrant s classes of Common Stock, as of February 12, 2010: Common Stock, par value $0.01 per share, 268,757,971 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 2010 Annual Meeting of Stockholders (the Company s 2010 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 United States (U.S.), China and other international power generation and steel production markets;
- price volatility and demand, particularly in higher-margin products and in our trading and brokerage businesses;
- reductions and/or deferrals of purchases by major customers and ability to renew sales contracts;
- credit and performance risks associated with customers, suppliers, 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;
- impact of weather on demand, production and transportation;
- 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 funding requirements;
- replacement and development of coal reserves;
- access to capital and credit markets and availability and costs of credit, margin capacity, surety bonds, letters of credit, and insurance;

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 federal or state 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 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 were incorporated in Delaware in 2001 and our history in the coal mining business dates back to 1883. 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. In response to growing international markets, we have expanded our international trading group in the last few years, most recently with the addition of a trading office in Singapore and a business development office in Indonesia.

In the U.S., we have transformed in recent years from a high-sulfur, high-cost coal company to a predominately low-sulfur, low-cost coal producer, marketer/trader of coal and manager of vast natural resources through organic growth, divestitures and strategic operational restructuring. Internationally, we expanded our presence through the acquisition of Excel Coal Limited (Excel) in Australia. 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 through coal-to-liquids and coal gasification technologies, and the advancement of clean coal technologies, including carbon capture and storage.

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), which is now an independent public company traded on the New York Stock Exchange (symbol PCX). The spin-off included eight company-operated mines, two joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves. Our results for all periods presented reflect Patriot as a discontinued operation.

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 through initiatives such as 1) participation in developing mine-mouth coal-fueled generating plants; 2) developing Btu Conversion technologies, which are designed to convert coal to natural gas and transportation fuels; and 3) advancing carbon capture and storage initiatives. Our operating segments are discussed in more detail below with financial information contained in Note 22 to our consolidated financial statements.

U.S. and Australian Mining Operations

Mining Segments. Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado operations, and our Midwestern U.S. Mining operations consist of our Illinois and Indiana operations. 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.

The maps below display our mine locations as of December 31, 2009. Also noted are the primary ports utilized in the U.S. and in Australia for our coal exports and our corporate headquarters. The U.S. map does not include our Bear Run Mine in western Indiana, which is expected to begin operations in mid-2010.

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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 2009. The mines are sorted by tons sold within each mining segment.

Mine	Location	Mine Type	Mining Method	Coal Type	Transport Method	2009 Tons Sold (In millions)
Western U.S. Mining						
North Antelope Rochelle	Wright, WY	S	DL, T/S	Thermal	R	98.3
Caballo	Gillette, WY	S	D, T/S	Thermal	R	23.3
Rawhide	Gillette, WY	S	D, T/S	Thermal	R	15.8
Twentymile	Oak Creek, CO	U	LW	Thermal	R, T	7.7
Kayenta	Kayenta, AZ	S	DL, T/S	Thermal	R	7.5
El Segundo	Grants, NM	S	T/S	Thermal	R	5.4
Lee Ranch	Grants, NM	S	DL, T/S	Thermal	R	2.1
Midwestern U.S. Mining						
Farmersburg	Pimento, IN	S	DL, D, T/S	Thermal	T, R	3.6
Willow Lake	Equality, IL	U	CM	Thermal	T/B	3.5
Gateway	Coulterville, IL	U	CM	Thermal	T, R, R/B	3.4
Somerville Central	Oakland City, IN	S	DL, D, T/S	Thermal	R, T/R, T/B	3.4
Cottage Grove	Equality, IL	S	D, T/S	Thermal	T/B	2.1
Francisco Underground	Francisco, IN	U	CM	Thermal	R	2.0
Somerville North	Oakland City, IN	S	D, T/S	Thermal	R, T/R, T/B	2.0
Miller Creek	Bicknell, IN	S	D, T/S	Thermal	T, T/R	2.0
Somerville South	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	1.6
Viking	Cannelburg, IN	S	D, T/S	Thermal	T, T/R	1.6
Wildcat Hills Underground	Eldorado, IL	U	CM	Thermal	T/B	0.7
Other(1)						4.2
Australian Mining						
Wilpinjong*	Wilpinjong, New South Wales	S	T/S	Thermal	R, EV	8.3
Burton*(2)	Glenden, Queensland	S	T/S	Thermal/Met	R, EV	2.5
Wilkie Creek	Macalister, Queensland	S	T/S	Thermal	R, EV	2.3
North Wambo Underground	Warkworth, New South Wales	U	LW	Thermal/Met**	R, EV	2.3
Wambo Open-Cut*	Warkworth, New South Wales	S	T/S	Thermal	R, EV	1.9
North Goonyella	Glenden, Queensland	U	LW	Met	R, EV	1.8
Metropolitan	Helensburgh, New South Wales	U	LW	Met	R, EV	1.5

Eaglefield*	Glenden, Queensland	S	T/S	Met	R, EV	0.9
Millennium	Moranbah, Queensland	S	T/S	Met	R, EV	0.8

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 coal is pulverized coal injection, or PCI

(1) 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 2009.

(2) 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.

In response to growing international markets, we expanded our international trading group in 2006 and added trading operations offices in London, England in 2007 and in Singapore in 2009. Our trading and brokerage entities broker and trade coal in the Australia and Pacific Rim markets. We also have sales, marketing and business development offices in Beijing, China and Jakarta, Indonesia (opened in 2009) 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 11.0 million tons of throughput in 2009. 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 control a 17.7% interest in the Newcastle Coal Infrastructure Group, which is currently constructing a coal transloading facility in Newcastle, Australia. The facility, which is expected to be completed in 2010, is backed by take or pay agreements and will have an initial capacity of 33 million tons per year of which our share is 5.8 million tons, with expansion capacity of up to 66 million tons per year.

Generation Development, Btu Conversion and Clean Coal Technology. 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. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal lessor. We are currently 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 plant is scheduled to begin generating electricity in 2011.

We are exploring Btu Conversion 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 also 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.

We are participating in the advancement of clean coal technologies, including carbon capture and storage, in the U.S., China and Australia. We are a founding member of the FutureGen Alliance, a non-profit company working in partnership with the U.S. Department of Energy (DOE), which under its new configuration, would develop multiple carbon capture and storage sites. We are the only non-Chinese equity partner in GreenGen, a near-zero emissions coal-fueled power plant with carbon capture and storage. In Australia, we made a 10-year commitment to fund the Australian COAL21 Fund designed to support clean coal technology demonstration projects and research in Australia. We are also a founding member or member of a number of related partnerships including the Global Carbon Capture and Storage Institute (Australia), the U.S.-China Energy Cooperation Program, the Asia-Pacific Partnership for Clean Development and Climate, the Consoritium for Clean Coal Utilization, the National Carbon Capture Center, and the Western Kentucky Carbon Storage Foundation.

Mongolia Joint Venture. In 2009, we acquired a 50% interest in a joint venture holding with Polo Resources Limited (AIM: PRL), which holds coal and mineral interests in Mongolia. In connection with this acquisition, we obtained warrants to enable us to acquire an approximate 15% equity interest in Polo Resources Limited. The joint venture is in the development stage and plans to ship metallurgical and thermal coal to Asian markets once developed.

Paso Diablo Mine. We own a 25.5% equity interest in Carbones del Guasare, S.A., a joint venture that includes Anglo American plc and a Venezuelan governmental partner. Carbones del Guasare operates the Paso Diablo Mine, which is a surface operation in northwestern Venezuela that produces thermal coal for export primarily to the U.S. and Europe. 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. In December 2009, we entered into an arrangement to assume Anglo American s interest, which is conditional on the approval of various parties (including the Venezuelan governmental partner) and regulatory approvals.

Coal Supply Agreements

As of January 31, 2010 we had a sales backlog of over one billion tons of coal, including backlog subject to price reopener and/or extension provisions, representing nearly five years of current production. Agreements in backlog have remaining terms ranging from one to 17 years. For 2009, approximately 93% of our worldwide sales (by volume) were under long-term coal supply agreements. In 2009, we sold coal to 345 electricity generating and industrial plants in 23 countries. For the year ended December 31, 2009, we derived 28% of our total coal sales revenues from our five largest customers (excluding trading transactions). At December 31, 2009, we had 79 coal supply agreements with these customers expiring at various times from 2010 to 2016.

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 international coal mining activities accounted for 10% of our mining operations sales volume in 2009. Our production is sold primarily into the export metallurgical and thermal markets. Price reopener provisions are present in the majority of our multi-year international coal agreements. Historically, these provisions allow either party to commence a renegotiation of the agreement price annually. A majority of the reopener provisions relate to metallurgical coal repriced annually in the second quarter of each year. We also have a long-term coal supply agreement with a customer in Australia, which runs through 2025 and is expected to supply approximately

130 million tons from our Wilpinjong Mine.

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). 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.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, ammonium-nitrate and emulsion based explosives, diesel fuel, off-the-road (OTR) tires, steel-related (including roof control materials) products and lubricants. 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. Although we have many well-established, strategic relationships with our key suppliers, we do not believe that we are dependent on any of our individual suppliers, except as noted below. The supplier base providing mining materials to the coal industry has been relatively consistent in recent years, although there continues to be some consolidation. Supplier consolidation in explosives and underground equipment has limited the number of sources for these materials, resulting in our purchases of these items being concentrated with one principal supplier; however, some supplier competition continues to be present. 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.

Technical Innovation

We continue to place great emphasis on the application of technical innovation to improve new and existing equipment performance. This research and development effort is typically undertaken and funded by equipment manufacturers using our input and expertise. Our engineering, maintenance and purchasing personnel work together with manufacturers to design and produce equipment that we believe will add value to the business. In 2009, we began a program to upgrade 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. Our engineers have also been working with several major equipment vendors to develop conceptual designs of in-pit crushing and conveying systems in place of trucks in an effort to move large quantities of overburden resulting in cost savings and a more environmentally friendly operation. We are currently working with a vendor to implement the Landmark longwall shearer navigation system at our North Wambo Underground 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. We have also begun pilot testing of a paste slurry pumping system that, if successful, will allow coal refuse from the Metropolitan Mine to be disposed of in abandoned areas of the underground workings rather than transported to the surface.

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 our two largest mines, North Antelope Rochelle and Caballo, to dispatch mobile equipment more efficiently and monitor performance and condition of all major mining equipment on a real-time basis.

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.

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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. According to the National Mining Association s 2008 Coal Producer Survey, the top 10 coal companies in the U.S. produced approximately 70% of total U.S. coal in 2008. 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 41% of total U.S. coal production in 2008 (most recent publicly available data). Major international competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Rio Tinto, Shenhua Group, and Xstrata PLC. In Australia, the top 10 coal companies produced approximately 84% of the country s coal in 2009. We compete on the basis of coal quality, delivered price, customer service and support and reliability.

Employees

As of December 31, 2009, we had approximately 7,300 employees, which included approximately 5,400 hourly employees. As of such date, approximately 29% of our hourly employees were represented by organized labor unions and generated 10% of 2009 coal production. Relations with our employees and, where applicable, organized labor are important to our success.

U.S. Labor Relations. Hourly workers at our Kayenta Mine in Arizona are represented by the United Mine Workers of America, under the Western Surface Agreement, which is effective through September 2, 2013. This agreement covers approximately 7% of our U.S. subsidiaries hourly employees, who generated approximately 4% of our U.S. production during the year ended December 31, 2009. Hourly workers at our Willow Lake Mine in Illinois are represented by the International Brotherhood of Boilermakers, under a labor agreement that expires April 15, 2011. This agreement covers approximately 9% of our U.S. subsidiaries hourly employees, who generated approximately 2% of our U.S. production during the year ended December 31, 2009.

Australian Labor Relations. The Australian coal mining industry is unionized and the majority of workers employed at our Australian 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. The current labor agreement at our Metropolitan Mine expires in June 2010; renegotiations for a new agreement will commence in the first quarter of 2010. The labor agreement for the Wambo Mine coal handling plant was renewed in 2008 and expires in 2011. The labor agreement for the Wambo Underground Mine was renewed in early 2009 and will expire in 2012. For the Wilkie Creek Mine (expired October 2009) and the North Goonyella Mine (expired May 2009), we have reached agreements in principle, with the vote of the unions and employees expected to take place in late February 2010.

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. 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 all accidents, incidents and losses to avoid reoccurrence. A portion of the annual performance incentives for our operating units is tied to their safety performance.

During 2009, our worldwide safety performance set a new standard in our 126-year history. The U.S. injury incidence rate of 2.06 (computed per 200,000 worker hours) was slightly higher compared to last year s record performance, but the Australian operations improved by nearly 40% versus the previous year. This drove the worldwide Peabody incidence rate to a new low of 2.82 for 2009, which was 21% better than the previous record year and approximately 31% better than the U.S. average for our industry. We received multiple state and federal safety awards during the year. Our training centers educate our employees in safety best practices and reinforce our company-wide belief that productivity and profitability follow when safety is the cornerstone at all of our operations.

Following passage of The Mine Improvement and New Emergency Response Act of 2006 (The Miner Act), the U.S. Mine Safety and Health Administration (MSHA), significantly increased the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. There has also been a dramatic increase in the dollar penalties assessed for citations issued over the past two years.

The Miner Act requires the installation of wireless, two-way communication systems for miners, and mine operators must have the ability to track the location of each miner at work in an underground mine. Since these developing technologies are nearly ready for MSHA approval, we anticipate expenditures in 2010 to fully equip all of our underground mines with this improved capability.

Most of the states in which we operate have inspection programs for mine safety and health. Collectively, federal and state safety and health regulations in the coal mining industry are perhaps the most comprehensive and pervasive systems for protection of employee health and safety affecting any segment of U.S. industry.

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.

SMCRA permit provisions include requirements for coal prospecting; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; surface drainage control; mine drainage and mine discharge control and treatment; and re-vegetation.

The U.S. mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining. Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land and documents required of the OSM s Applicant Violator System.

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 the U.S. Bureau of Alcohol, Tobacco and Firearms regulates the use of explosive blasting.

We do not believe there are any matters that pose a material risk to maintaining our existing mining permits or materially hinder our ability to acquire future mining permits. It is our policy to comply in all material respects 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 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

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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 and other substances emitted by coal-based electricity generating plants. In addition to the issues discussed under Global Climate Change on page 14, the 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), Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and New Source Review. In addition, the EPA has adopted NAAQS for particulate matter, nitrogen oxide and sulfur dioxide. The EPA has proposed more stringent NAAQS for sulfur dioxide and ozone. Almost all of these programs and regulations have resulted in litigation which has not been completely resolved.

Programs such as the Acid Rain Program and CAIR use a cap and trade system. Affected power plants have sought to reduce sulfur dioxide emissions by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing or trading sulfur dioxide emissions allowances. As a result of the CAIR program, the MACT requirements and more stringent nitrogen oxides, particulate and ozone NAAQS, many power plants have been or will be required to install additional emission control measures, such as scrubbers and selective catalytic reduction devices.

Our customers are among the electricity generators subject to New Source Review enforcement actions and if found not to be in compliance, our customers could be required to install additional control equipment at the affected plants or they could decide to close some or all of those plants. The Regional Haze program may also require retrofitting of existing facilities with additional control equipment.

In recent years Congress has considered legislation that would require reductions in emissions of sulfur dioxide, nitrogen oxide and mercury, greater and sooner than those required by existing law. No such legislation has passed either house of Congress. If enacted into law, such legislation could impact the amount of coal supplied to electricity generating customers if they decide to switch to other sources of fuel whose use would result in lower emissions of sulfur dioxide, nitrogen oxide and mercury.

Clean Water Act. The Clean Water Act of 1972 affects U.S. coal mining operations by requiring effluent limitations and treatment standards for waste water 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 into water. Section 404 under 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 enforce 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 its water quality standards and other applicable requirements in deciding whether or not to certify the activity.

Total Maximum Daily Load (TMDL) regulations established a process by which states designate stream segments as impaired (not meeting present water quality standards). Industrial dischargers, including coal mines, may be required to meet new TMDL effluent standards for these stream segments. States are also adopting anti-degradation regulations in which a state designates certain water bodies or streams as high quality/exceptional use. These regulations would restrict the diminution of water quality in these streams. Waters discharged from coal mines to high quality/exceptional use streams may be required to meet additional conditions or provide additional demonstrations and/or justification. In general, these Clean Water Act requirements could result in higher water treatment and permitting costs or permit delays, which could adversely affect our coal production costs or efforts.

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 non-hazardous 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 has announced that it is developing a proposal for requirements for coal combustion residue management.

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.

The Energy Policy Act of 2005. The Domenici-Barton Energy Policy Act of 2005 (EPACT) was signed by President Bush in August 2005. EPACT contains tax incentives and directed spending totaling an estimated $14.1 billion intended to stimulate supply-side energy growth and increased efficiency. In addition to rules affecting the leasing process of federal coal properties, EPACT programs and incentives include funding to demonstrate advanced coal technologies, including coal gasification; grants and a loan guarantee program to encourage deployment of advanced clean coal-based power generation technologies, including integrated gasification combined cycle (IGCC); a federal loan guarantee program for the cost of advanced fossil energy projects, including coal gasification; funding for energy research, development, demonstration and commercial application programs relating to coal and power systems; and tax incentives for IGCC, industrial gasification and other advanced coal-based generation projects, as well as for coal sold from Indian lands. Finally, certain sections of EPACT are potentially applicable to the area of Btu Conversion, such as the fossil energy project loan guarantee program as well as a provision allowing taxpayers to capitalize 50% of the cost of refinery investments which increase the total throughput of qualified fuels including synthetic fuels produced from coal by at least 25%. In addition, EPACT requires the Secretary of Defense to develop a strategy to use fuel produced from coal, oil shale and tar sands (covered fuel) to assist in meeting the fuel requirements of the U.S. Department of Defense (DOD). The law authorizes the DOD to enter into multi-year contracts to procure a covered fuel to meet one or more of its fuel requirements and to carry out an assessment of potential locations for covered fuel sources.

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 associated 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.

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

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 (NTA) 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. Native title rights can be extinguished either by a valid act of government (as set out in the NTA) or by the loss of connection between the land and the group of Aboriginal peoples concerned.

The NTA provides that where native title rights still exist and the mining project will affect those native title rights, it is necessary to consult with the relevant Aboriginal group and to come to an agreement on issues such as the preservation of sacred or important sites, the employment of members of the group by the mine operator, and the payment of compensation for the effect on native title of the mining project. In the absence of agreement with the relevant Aboriginal group, the NTA provides for arbitration.

There is also federal and state legislation to prevent damage to Aboriginal cultural heritage and archeological sites.

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 local, 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.

Generally, the process involves an assessment of the environmental impacts of the project and how these can be managed which is submitted to the state government for consideration (also to the federal government if federal approval is required). Based on the environmental assessment, conditions will be imposed on the environmental approval (if granted). The conditions commonly relate to limits on emissions to the atmosphere, emissions in water, noise impacts, dust impacts, the generation, handling, storage and transportation of waste and requirements for the rehabilitation and restoration of land. Environmental assessments and applications for approval are generally publicly notified and third parties may lodge submissions.

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Queensland and New South Wales each have their own mining tenement legislation which regulates the process for applying for and renewing mining tenements. Before obtaining a mining lease which allows production, it is necessary to hold an exploration license. This exploration license allows exploratory drilling to take place but does not permit production.

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.

It is mandatory for an employer to have insurance coverage with respect to the compensation of injured workers; similar coverage is in effect throughout Australia which is of a no fault nature and which provides for benefits up to a prescribed level. The specific benefits vary by jurisdiction, but generally include the payment of weekly compensation to an incapacitated employee, together with payment of medical, hospital and related expenses. The injured employee has a right to sue his or her employer for further damages if a case of negligence can be established.

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 regulates 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 of consumption limits in Australia (controlling corporations) must comply with the NGER Act.

Peabody Energy Australia Pty Ltd, 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

The Mongolian mining industry 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 Change

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

Presently there are no U.S. federal mandatory greenhouse gas reduction requirements. In June 2009, the U.S. House of Representatives passed legislation which calls for a cap-and-trade system and other measures. Under a cap-and-trade program, or emissions trading scheme, allowances would be granted or auctioned, with the quantity based on the acceptable limits of aggregate emissions. Over time, those allowable emissions would likely be decreased. The price would depend on a number of factors including the market for such allowances and the cost of emissions control technologies or alternatives. The U.S. Senate has not acted on legislation in this area. While it is possible that the U.S. will adopt legislation in the future, the timing and specific requirements of any such legislation are highly uncertain.

Even in the absence of new U.S. federal legislation, greenhouse gas emissions may be regulated in the future by the U.S. EPA pursuant to the Clean Air Act. In response to the 2007 U.S. Supreme Court ruling Massachusetts v. EPA that the EPA has authority to regulate carbon dioxide emissions under the Clean Air Act, the EPA has taken several actions towards emissions regulation.

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. The finding does not by itself impose any regulatory requirements and does not contain any specific targets for reducing greenhouse gases. While the EPA s finding is technically limited to greenhouse gas emissions from new motor vehicles and new motor vehicle engines, the finding may lead to endangerment findings under other Clean Air Act programs, including those that relate directly to emissions from stationary sources. In February 2010, we filed a petition with the EPA requesting reconsideration of the finding as well as a petition to review the finding with the U.S. Court of Appeals for the District of Columbia Circuit. Our petitions are based primarily on the release of email and other information from the University of East Anglia Climatic Research Unit (CRU) in November 2009. We believe that the CRU information undermines a number of the central pillars on which the finding rests, particularly the work of the IPCC.

In October 2009, the EPA published a proposed rule to regulate the emission of greenhouse gases from certain stationary sources with an initial focus on facilities that release more than 25,000 tons of greenhouse gases a year, and that would require best available control technology for such emissions whenever such facilities are built or significantly modified (the so-called tailoring rule). It is unclear as to whether the EPA has the statutory authority under the Clean Air Act to adopt the tailoring rule. In addition, in September 2009 the EPA adopted a rule requiring certain emitters of greenhouse gases, including coal-fired power plants, to monitor and report their emissions to the EPA.

A number of states in the U.S. have taken steps 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 (RGGI), 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 regional greenhouse gas reduction targets and develop a multi-sector cap-and-trade system to help meet the targets. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and two Canadian provinces have entered into the Western Climate Initiative (WCI) to establish a regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. However, the Governor of Arizona announced in February 2010 that Arizona will not implement the greenhouse gas cap-and-trade proposal advanced by the WCI, which begins on January 1, 2012. 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.

In December 1997, in Kyoto, Japan, the signatories to the 1992 Framework Convention on Climate Change, which addresses emissions of greenhouse gases, established a binding set of emission targets for developed nations. The U.S. has signed the Kyoto Protocol, but it has not been ratified by the U.S. Senate. As noted previously, Australia ratified the Kyoto Protocol in December 2007 and became a full member in March 2008. International discussions are underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2012, including the Copenhagen meetings in late 2009.

In May 2009, legislation was introduced in Australia s Parliament to establish a national emissions trading market, called the Carbon Pollution Reduction Scheme (CPRS). If enacted, the CPRS would set a cap on greenhouse gas emissions in Australia and issue permit allowances up to the cap limit. The CPRS was passed by Australia s House of Representatives in June 2009, but was voted down by the Australian Senate in August 2009. The Australian government reintroduced the CPRS for consideration by Parliament in October 2009, but it was voted down by the Australian Senate in December 2009.

We continue to support clean coal technology development and other initiatives addressing global climate change through our participation as a founding member of the FutureGen Alliance in the U.S. and the COAL21 Fund in Australia and through our participation 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 addition, we are the only non-Chinese equity partner in GreenGen, the first near-zero emissions coal-fueled power plant with carbon capture and storage which is under development in China. We are also a founding member of the Global Carbon Capture and Storage Institute, an international initiative to accelerate commercialization of carbon capture and storage (CCS) technologies through development of 20 integrated, industrial-scale demonstration projects.

In the U.S., clean coal technology development is being accelerated by the American Recovery and Reinvestment Act of 2009 (the ARRA), which was signed into law by President Obama in February 2009. The ARRA targets $3.4 billion for U.S. 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.

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 coal at our mines. We continue to evaluate and implement improvements in technology and infrastructure such as the overland conveyor and near pit truck dump and crusher facility at our North Antelope Rochelle Mine in Wyoming that are expected to reduce the level of emissions from our operations.

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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

The global economic recession and disruptions in the financial markets, and their impact on us, are uncertain.

The magnitude and pace of recovery from the global economic recession and the worldwide financial and credit market disruptions is uncertain. We are focused on strong cost control and productivity improvements, increased contributions from our high-margin operations, and exercising tight capital discipline. However, there can be no assurance that these actions, or any others that we may take in response to further deterioration in economic and financial conditions, will be sufficient. A return to the global recession or further disruptions in the financial markets could have an adverse effect on our business, financial condition or results of 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 annual repricing of our metallurgical coal contracts;

the supply of U.S. domestic and international thermal and metallurgical coal;

competition within our industry and the availability and price of alternative fuels and energy sources;

the proximity, capacity and cost of transportation;

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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.

As of January 26, 2010, we are fully contracted for 2010 at planned production levels in the U.S. and have 4.5 to 5.5 million tons of Australian metallurgical coal and 6.5 to 7.0 million tons of Australian thermal coal available to price. 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 2009, 93% of our worldwide sales volume was sold under long-term coal supply agreements. At January 31, 2010, our sales backlog, including backlog subject to price reopener and/or extension provisions, was over one billion tons, representing nearly five years of current production in backlog. Contracts in backlog have remaining terms ranging from one to 17 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 assure you 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.

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

In 2009, we derived 28% of our total coal sales revenues from our five largest customers (excluding trading transactions). At December 31, 2009, we had 79 coal supply agreements with these customers expiring at various times from 2010 to 2016. 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 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 as utilities have sold their power plants to their non-regulated affiliates or third parties. These new power plant owners or other customers may have credit ratings that are below investment grade. If deterioration of the creditworthiness of our customers occurs, our $275.0 million 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, 2009, 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, 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.

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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, explosives, fuel, tires, steel-related products (including roof control) and lubricants. Recent consolidation of suppliers of explosives has limited the number of sources for these materials, and our current supply of explosives is concentrated with one supplier. Further, our purchases of some items of underground mining equipment are concentrated with one principal supplier. 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.

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 is 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 our exposure to explosives, diesel fuel, foreign currency and interest rate fluctuations. 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.

Additionally, some of our hedging arrangements require us to post margin based on the value of those hedging arrangements 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. We cannot assure you 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, 2009, we had approximately 7,300 employees. Approximately 29% of our hourly employees were represented by unions and they generated approximately 10% of our 2009 coal production. Additionally, those employed through contract mining relationships in Australia are also members of 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.

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 for us 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, 2009, we had $821.9 million of self bonding in place for our reclamation obligations. As of December 31, 2009, we also had outstanding surety bonds with third parties and letters of credit of $1,270.3 million, of which $807.2 million was for post-mining reclamation, $51.7 million related to workers compensation obligations, $116.3 million was for coal lease obligations and $295.1 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 our successful renewal of our Senior Unsecured Credit Facility, which expires in 2011. Our failure to maintain, 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 Senior Unsecured Credit Facility;
- the exercise by third-party surety bond issuers of their right to refuse to renew the surety; and
- 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.

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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 judicial interpretations 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 operation, 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, 2009, we leased a total of 64,260 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 are 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 and Singapore. We also have joint venture mining and exploration interests in Venezuela and Mongolia. 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 operation, 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 Senior Unsecured Credit Facility.

As of December 31, 2009, we had $1.5 billion of available borrowing capacity under our Senior Unsecured Credit Facility, net of outstanding letters of credit. This committed facility, which matures on September 15, 2011, 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. If one or more of the financial institutions providing the Senior Unsecured Credit Facility 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, 2009, our total indebtedness was $2.8 billion, and we had $1.5 billion of available borrowing capacity under our Senior Unsecured Credit Facility. The indentures governing our Convertible Junior Subordinated

Debentures (the Debentures) and 7.375% and 7.875% Senior Notes do not limit the amount of indebtedness that we may issue, and the indentures governing our 6.875% and 5.875% Senior Notes permit 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, acquisitions, 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, acquisitions, 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 Senior Unsecured Credit Facility 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 consummate 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 Senior Unsecured Credit Facility and the indentures governing our Senior Notes and Debentures impose restrictions that may limit our operating and financial flexibility.

Our Senior Unsecured Credit Facility, the indentures governing our 6.875% and 5.875% Senior Notes and Debentures and the instruments governing our other indebtedness contain certain restrictions and covenants which restrict our ability to incur liens and debt or provide guarantees in respect of obligations of any other person. Under our Senior Unsecured Credit Facility, 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. These covenants and restrictions are reasonable and customary and have not impacted our business in the past.

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 Senior Unsecured Credit Facility. If we violate these covenants and are unable to obtain waivers from our lenders, our debt under our Senior Unsecured Credit Facility and our 6.875% and 5.875% Senior Notes and 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, on terms that are acceptable to us or at all. 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 $982.2 million as of December 31, 2009, $68.1 million of which was a current liability. Net pension liabilities were $215.3 million as of December 31, 2009, $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.

The decline in the stock market and real estate values which occurred in 2008 and 2009 led to a decline in the value of our pension plan assets which required an increase in contributions in 2009 and will likely require increased contributions in future years.

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Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate change, 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 change continues 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 change. In turn, increasing government attention is being paid to global climate change 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 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 carbon capture and storage 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. For example, some companies capitalize drilling and related costs incurred to delineate and classify mineral resources as proven and probable reserves, and other companies expense such costs. In addition, some industry participants expense pre-production stripping costs associated with developing new pits at existing surface mining operations, while other companies capitalize pre-production stripping costs for new pit

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development at existing operations. The materiality of such expenditures can vary greatly relative to a given company s respective financial position and results of operations. 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, 2009. An estimated 7.9 billion tons of our proven and probable coal reserves are in the U.S. and 1.1 billion tons are in Australia. 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 39% of these reserves and lease property containing the remaining 61%. 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. 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, 2009[1]		
Operating Regions	**Locations**	**Owned Tons**	**Leased Tons (Tons in millions)**	**Total Tons**
Midwest	Illinois, Indiana and Kentucky	2,627	939	3,566
Powder River Basin	Wyoming and Montana	67	2,948	3,015
Southwest	Arizona and New Mexico	811	309	1,120
Colorado	Colorado	44	196	240
Total United States		3,549	4,392	7,941
Australia	New South Wales		451	451
Australia	Queensland		623	623
Total Australia			1,074	1,074
Total Proven and Probable Coal Reserves		3,549	5,466	9,015

(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, 2009, we leased 11,592 acres of federal land in Colorado, 11,256 acres in Montana and 41,412 acres in Wyoming, for a total of 64,260 nationwide.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 65,000 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 sale prices. 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, 2009, 2008 and 2007, 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, 2009	Year Ended Dec. 31, 2008	Year Ended Dec. 31, 2007	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
	1.6	1.9	2.1	Thermal	17	1	32	11,300	50	2	
				Thermal	2	30	194	11,100	226	112	1
	2.0	1.9	1.6	Thermal		1	21	11,100	22	21	
ed out in 2009)	1.4	1.9	2.2	Thermal				11,100			
	2.0	1.5	0.9	Thermal			46	11,300	46	8	
	3.5	3.4	3.5	Thermal		1	20	10,900	21	18	
	3.3	3.5	3.4	Thermal				NA			
	2.0	2.2	2.5	Thermal			2	11,200	2	2	
	1.8	2.2	2.5	Thermal			16	11,100	16	12	
	1.6	1.6	1.7	Thermal		1	6	11,500	7		
	0.7	0.7	0.9	Thermal			15	12,400	15	8	
und	2.1	2.2	2.0	Thermal			23	12,200	23	15	
	3.4	3.6	3.6	Thermal			25	12,100	25	18	
	3.3	3.2	2.7	Thermal			18	11,000	18	17	
	28.7	29.8	29.6		19	34	418		471	233	2
e	98.3	97.6	91.5	Thermal	850		9	8,700	859		8
	23.3	31.2	31.2	Thermal	681	131	33	8,200	845		8
	15.8	18.4	17.2	Thermal	290	66	24	8,300	380		3
	137.4	147.2	139.9		1,821	197	66		2,084		2,0
	7.5	8.0	8.0	Thermal	171	81	4	11,100	256		2
	1.8	3.3	5.3	Thermal	19	144	21	9,400	184	144	
	7.8	8.0	8.3	Thermal	49			11,200	49	8	
	5.1	3.3		Thermal	25	88	69	9,300	182	168	
	22.2	22.6	21.6		264	313	94		671	320	3

efield	2.5	2.8	2.8	Met.	38			12,900	38		
	1.5	1.5	1.5	Met.	44			12,600	44		
	2.3	2.6	2.4	Thermal	370			10,800	370		3
	4.1	5.4	4.4	Thermal/Met.	201			12,200	201		2
	2.0	2.6	3.1	Thermal/Met.	33			12,700	33		
	8.4	7.5	5.1	Thermal		206		11,200	206		2
	0.9	1.2	1.3	Met.	41			12,600	41		
	21.7	23.6	20.6		727	206			933		9
tions	210.0	223.2	211.7		2,831	750	578		4,159	553	3,6
s	0.8	2.0	19.4								
	210.8	**225.2**	**231.1**		**2,831**	**750**	**578**		**4,159**	**553**	**3,6**

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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, 2009

(Tons in Millions)

Total Tons		Proven and Probable			Type of	Sulfur Content(2)			As	Reserve Control	
						<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		
Assigned	Unassigned	Reserves	Proven	Probable	Coal				pound(3)	Owned	Leased
81	2,193	2,274	1,161	1,113	Thermal			2,274	10,900	1,902	372
390	412	802	571	231	Thermal	19	39	744	11,200	451	351
	490	490	230	260	Thermal		1	489	11,800	274	216
471	3,095	3,566	1,962	1,604		19	40	3,507		2,627	939
	162	162	158	4	Thermal	9	121	32	8,500	67	95
2,084	769	2,853	2,811	42	Thermal	2,625	196	32	8,500		2,853
2,084	931	3,015	2,969	46		2,634	317	64		67	2,948
256		256	256		Thermal	173	81	2	11,100		256
49	191	240	149	91	Thermal	193		47	10,700	44	196
366	498	864	777	87	Thermal	160	373	331	9,000	811	53
671	689	1,360	1,182	178		526	454	380		855	505
451		451	372	79	Thermal/Met.	247	204		11,800		451
482	141	623	351	272	Thermal/Met.	623			11,300		623
933	141	1,074	723	351		870	204				1,074
4,159	4,856	9,015	6,836	2,179		4,049	1,015	3,951		3,549	5,466

(1) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2009. 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) 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. *Submission of Matters to a Vote of Security Holders.*

No matters were submitted to a vote of security holders during the quarter ended December 31, 2009.

Executive Officers of the Company

Set forth below are the names, ages as of February 24, 2010 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	55	Chairman and Chief Executive Officer, Director
Richard A. Navarre	49	President and Chief Commercial Officer
Michael C. Crews	43	Executive Vice President and Chief Financial Officer
Sharon D. Fiehler	53	Executive Vice President and Chief Administrative Officer
Eric Ford	55	Executive Vice President and Chief Operating Officer
Alexander C. Schoch	55	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 Vice Chairman of the World Coal Institute and the National Mining Association. He is a member of 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 Board of Trustees of St. Louis Children s Hospital; the Board of Trustees of Washington University in St. Louis; the School of Engineering and Applied Science National Council at 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; a member of the Board of Directors of the Regional Chamber and Growth Association of St. Louis; a Director of the United Way of Greater St. Louis; a Vice Chair of the Missouri Historical Society; a member of Financial Executives International and the Civic Entrepreneurs Organization; 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 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. She is a member of the Executive Committee and Board of Directors of Junior Achievement of St. Louis; 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 and a recipient of the 2008 YWCA Leader of Distinction Award.

Eric Ford was named our Executive Vice President and Chief Operating Officer in March 2007. Mr. Ford has 38 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.

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 12, 2010, there were 1,395 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
2008			
First Quarter	$ 63.97	$ 42.05	$ 0.06
Second Quarter	88.69	49.38	0.06
Third Quarter	88.39	39.06	0.06
Fourth Quarter	43.99	16.00	0.06
2009			
First Quarter	$ 30.95	$ 20.17	$ 0.06
Second Quarter	37.44	23.56	0.06
Third Quarter	41.54	27.19	0.06
Fourth Quarter	48.21	34.54	0.07

Dividend Policy

We paid quarterly dividends totaling $0.25 per share and $0.24 per share for the years ended December 31, 2009 and 2008, respectively. Most recently, our Board of Directors declared a dividend of $0.07 per share of Common Stock on January 27, 2010, payable on March 3, 2010, to stockholders of record on February 10, 2010. 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

Our Board of Directors has 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, 2009, we have made repurchases of 7.7 million shares at a cost of $299.6 million, leaving $700.4 million available for share repurchase under the program.

The following table summarizes all share repurchases for the three months ended December 31, 2009:

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, 2009	558	$ 43.37		$ 700.4
November 1 through November 30, 2009	1,358	39.59		$ 700.4
December 1 through December 31, 2009	570	45.21		$ 700.4
Total	2,486	$ 41.73		

(1) Represents 2,486 shares withheld to cover the withholding taxes upon the vesting of restricted stock.

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 2009, 2008 and 2007 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. 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, 2009, 2008, 2007, 2006 and 2005 from our audited financial statements. You should read the following table in 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.

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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 of this report includes a discussion of risk factors that could impact our future results of operations.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	$ 6,012.4	$ 6,561.0	$ 4,523.8	$ 4,045.6	$ 3,597.9
Costs and expenses	5,167.6	5,164.7	3,924.1	3,432.8	3,166.3
Operating profit	844.8	1,396.3	599.7	612.8	431.6
Interest expense, net	193.1	217.0	228.8	127.8	88.9
Income from continuing operations before income taxes	651.7	1,179.3	370.9	485.0	342.7
Income tax provision (benefit)	193.8	191.4	(70.7)	(85.6)	62.3
Income from continuing operations, net of income taxes	457.9	987.9	441.6	570.6	280.4
Income (loss) from discontinued operations, net of income taxes	5.1	(28.8)	(180.1)	30.7	144.8
Net income	463.0	959.1	261.5	601.3	425.2
Less: net income (loss) attributable to noncontrolling interests	14.8	6.2	(2.3)	0.6	2.5
Net income attributable to common stockholders	$ 448.2	$ 952.9	$ 263.8	$ 600.7	$ 422.7
Basic earnings per share from continuing operations[1]	$ 1.66	$ 3.63	$ 1.67	$ 2.15	$ 1.06
Diluted earnings per share from continuing operations[1]	$ 1.64	$ 3.60	$ 1.64	$ 2.11	$ 1.04
Weighted average shares used in calculating basic earnings per share	265.5	268.9	264.1	263.4	261.5
Weighted average shares used in calculating diluted earnings per share	267.5	270.7	268.6	268.8	267.3
Dividends declared per share	$ 0.25	$ 0.24	$ 0.24	$ 0.24	$ 0.17
Other Data					
Tons sold	243.6	255.0	235.5	221.2	213.7
Net cash provided by (used in) continuing operations:					
Operating activities	$ 1,053.5	$ 1,409.8	$ 460.7	$ 611.1	$ 672.4
Investing activities	(408.2)	(419.3)	(538.9)	(2,055.6)	(506.3)
Financing activities	(102.3)	(487.0)	41.7	1,403.0	(41.4)
Adjusted EBITDA	1,290.1	1,846.9	969.7	909.7	696.4

Balance Sheet Data (at period end)					
Total assets	$ 9,955.3	$ 9,695.6	$ 9,082.3	$ 9,504.7	$ 6,852.0
Total long-term debt (including capital leases)	2,752.3	2,793.6	2,909.0	2,911.6	1,332.0
Total stockholders equity	3,755.9	3,119.5	2,735.3	2,587.0	2,178.5

(1) Effective January 1, 2009, we adopted the two-class method to compute basic and diluted earnings per share. This method has been retrospectively applied to all periods presented.

Adjusted EBITDA is calculated as follows (unaudited):

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(Dollars in millions)				
Income from continuing operations, net of income taxes	$ 457.9	$ 987.9	$ 441.6	$ 570.6	$ 280.4
Income tax provision (benefit)	193.8	191.4	(70.7)	(85.6)	62.3
Depreciation, depletion and amortization	405.2	402.4	346.3	282.7	244.9
Asset retirement obligation expense	40.1	48.2	23.7	14.2	19.9
Interest expense, net	193.1	217.0	228.8	127.8	88.9
Adjusted EBITDA	$ 1,290.1	$ 1,846.9	$ 969.7	$ 909.7	$ 696.4

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 2009, we produced 210.0 million tons of coal and sold 243.6 million tons of coal. For 2009, our U.S. sales represented 19% of U.S. coal consumption and were approximately 50% greater than the sales of our closest U.S. competitor.

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 2009, metallurgical coal was approximately 3% of our total sales volume, but represented a larger share of our revenue, approximately 23%.

We typically sell coal to utility customers under long-term contracts (those with terms longer than one year). During 2009, approximately 93% of our worldwide sales (by volume) were under long-term contracts. For the year ended December 31, 2009, 81% of our total sales (by volume) were to U.S. electricity generators, 17% 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 development of coal-fueled generating and Btu Conversion projects in areas of the U.S. where electricity demand is strong and where there is access to land, water, transmission lines and low-cost coal. Coal-fueled generating projects may involve mine-mouth generating plants using our surface lands and coal reserves. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal sales. Currently, we own 5.06% of the 1,600-megawatt Prairie State Energy Campus that is under construction in Washington County, Illinois.

We are determining how to best participate in Btu Conversion technologies to economically convert our coal resources to natural gas and transportation fuels through the Kentucky NewGas and GreatPoint Energy projects in the U.S. We are also advancing the development of clean coal technologies, including carbon

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capture and sequestration, through a number of initiatives that include the FutureGen Alliance and university research programs in the U.S., GreenGen in China and COAL21 Fund in Australia.

As discussed more fully in Item 1A. Risk Factors, our results of operations in the near-term could be negatively impacted by the rate of the economic recovery, adverse weather conditions, unforeseen geologic conditions or equipment problems at mining locations and by the availability of transportation for coal shipments. 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 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, 2009 Compared to Year Ended December 31, 2008

Summary

Our overall results for 2009 compared to 2008 reflect the unfavorable impact of lower global demand for coal as a result of the global economic recession. Despite the recession, our 2009 Adjusted EBITDA was the second highest in our 126-year history and second only to our 2008 Adjusted EBITDA. We also ended 2009 with total available liquidity of $2.5 billion. We continue to focus on strong cost control and productivity improvements, increased contributions from our high-margin operations and exercising tight capital discipline.

Our 2009 tons sold were below prior year levels reflecting planned production reductions in the Powder River Basin to match lower demand, partially offset by increased volumes associated with the full-year operation of our El Segundo Mine in the Southwest. In the U.S., the decreased demand from lower industrial output, lower natural gas prices that resulted in higher fuel switching, and higher coal stockpiles in the U.S. led to an 8.5 million ton decline in sales volume. In Australia, lower demand from steel customers resulted in a 1.3 million ton decline in metallurgical coal volume, although volumes in the second half of 2009 began to increase on an improved economic outlook led by demand from Asian-Pacific markets.

Our 2009 revenues declined compared to 2008 and were primarily impacted by Australia s lower annual export contract pricing that commenced on April 1, 2009 as compared to 2008 s record pricing and the overall decline in volume. Lower revenues were also driven by the decline in Trading and Brokerage revenues that resulted from lower coal pricing volatility. The lower Australian and Trading and Brokerage revenues were partially offset by an increase in U.S. revenues per ton that reflect multi-year contracts signed at higher prices in recent years.

While our Segment Adjusted EBITDA reflects the lower revenue discussed above, our 2009 margins also reflect the impact of producing at reduced levels as well as higher sales related costs. In addition, our costs in Australia were higher due to two additional longwall moves compared to 2008 and the impact of mining in difficult geologic conditions that also included higher costs for overburden removal.

Net income declined in 2009 compared to 2008 reflecting the above items, as well as lower results from equity affiliates and decreased net gains on disposals of assets. Income from continuing operations, net of income taxes was $457.9 million in 2009, or $1.64 per diluted share, 53.6% below 2008 income from continuing operations, net of income taxes of $987.9 million, or $3.60 per diluted share.

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Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2009 and 2008:

	Year Ended December 31,		Increase (Decrease)	
	2009	2008	Tons	%
	(Tons in millions)			
Western U.S. Mining	160.1	169.7	(9.6)	(5.7)%
Midwestern U.S. Mining	31.8	30.7	1.1	3.6%
Australian Mining	22.3	23.4	(1.1)	(4.7)%
Trading and Brokerage	29.4	31.2	(1.8)	(5.8)%
Total tons sold	243.6	255.0	(11.4)	(4.5)%

Revenues

The following table presents revenues for the years ended December 31, 2009 and 2008:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2009	2008	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 2,612.6	$ 2,533.1	$ 79.5	3.1%
Midwestern U.S. Mining	1,303.8	1,154.6	149.2	12.9%
Australian Mining	1,678.0	2,242.8	(564.8)	(25.2)%
Trading and Brokerage	391.0	601.8	(210.8)	(35.0)%
Other	27.0	28.7	(1.7)	(5.9)%
Total revenues	$ 6,012.4	$ 6,561.0	$ (548.6)	(8.4)%

2009 revenues were below prior year driven by decreases in our Australian Mining and Trading and Brokerage segments as discussed below:

Australian Mining operations average sales price decreased 21.4% from the prior year reflecting the lower annual export contract pricing that commenced April 1, 2009 compared to the record pricing realized in 2008. The price decreases were combined with volume decreases from the prior year (4.7%) due to overall lower demand experienced in the first half of 2009. 2009 metallurgical coal shipments of 6.9 million tons were 1.3 million tons below prior year. In the second half of 2009, 5.0 million tons of metallurgical coal were shipped, reflecting a partial recovery from the lower metallurgical coal shipments that occurred in the first half of the year.

Trading and Brokerage revenues decreased from the prior year primarily due to lower coal pricing volatility in 2009 resulting in lower margins on trading transactions, partially offset by profit from business contracted in 2008 that was realized in 2009 on an international brokerage arrangement.

These decreases to revenues were partially offset by revenue increases in our Midwestern U.S. and Western U.S. Mining segments as discussed below:

Midwestern U.S. Mining operations average sales price increased over the prior year (9.3%) driven by the benefit of higher Illinois Basin prices and increased shipments, including purchased coal used to satisfy certain coal supply agreements.

Western U.S. Mining operations average sales price increased over the prior year (9.2%) due to a combination of higher contract pricing and a shift in sales mix. Revenues were also higher due to increased shipments from our El Segundo Mine (commissioned in June 2008) and customer contract termination and restructuring agreements. These increases were partially offset by the prior year revenue recovery on a long-term coal supply agreement ($56.9 million) and an overall volume decrease (5.7%) reflecting our planned Powder River Basin production decreases to match demand.

Segment Adjusted EBITDA

The following table presents segment Adjusted EBITDA for the years ended December 31, 2009 and 2008:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2009	2008	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 721.5	$ 681.3	$ 40.2	5.9%
Midwestern U.S. Mining	281.9	177.3	104.6	59.0%
Australian Mining	437.8	1,016.6	(578.8)	(56.9)%
Trading and Brokerage	193.4	218.9	(25.5)	(11.6)%
Total Segment Adjusted EBITDA	$ 1,634.6	$ 2,094.1	$ (459.5)	(21.9)%

Australian Mining operations Adjusted EBITDA decreased compared to the prior year due to lower annual export contract pricing and lower sales volume due to reduced demand ($416.0 million) as discussed above. Also impacting the segment s Adjusted EBITDA was higher production costs ($170.7 million) driven by increased overburden stripping ratios and decreased longwall mine performance, which included higher costs associated with two additional longwall moves in 2009 compared to 2008.

Trading and Brokerage Adjusted EBITDA decreased compared to prior year primarily due to lower net revenue discussed above.

Western U.S. Mining operations Adjusted EBITDA increased over the prior year driven by higher pricing ($205.5 million), partially offset by lower demand ($63.2 million), a prior year revenue recovery on a long-term coal supply agreement ($56.9 million), higher sales related costs ($52.0 million) and lower productivity due to increased stripping ratios ($20.8 million). The impact of lower demand was partially mitigated by revenues from customer contract termination and restructuring agreements ($27.8 million).

Midwestern U.S. Mining operations Adjusted EBITDA increased over the prior year primarily due to higher pricing ($110.7 million) and decreased commodity costs ($16.0 million), partially offset by higher costs associated with mining in more difficult geological conditions compared to the prior year ($20.7 million).

Income From Continuing Operations Before Income Taxes

The following table presents income from continuing operations before income taxes for the years ended December 31, 2009 and 2008:

Increase (Decrease) to Income

	Year Ended December 31,			
	2009	2008	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 1,634.6	$ 2,094.1	$ (459.5)	(21.9)%
Corporate and Other Adjusted EBITDA	(344.5)	(247.2)	(97.3)	(39.4)%
Depreciation, depletion and amortization	(405.2)	(402.4)	(2.8)	(0.7)%
Asset retirement obligation expense	(40.1)	(48.2)	8.1	16.8%
Interest expense	(201.2)	(227.0)	25.8	11.4%
Interest income	8.1	10.0	(1.9)	(19.0)%
Income from continuing operations before income taxes	$ 651.7	$ 1,179.3	$ (527.6)	(44.7)%

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Income from continuing operations before income taxes decreased from prior year primarily due to the lower Total Segment Adjusted EBITDA discussed above and lower Corporate and Other Adjusted EBITDA, partially offset by lower interest expense and asset retirement obligation expense.

The decrease of $97.3 million in Corporate and Other Adjusted EBITDA during 2009 compared to 2008 was due to the following:

Lower results from equity affiliates ($69.1 million) primarily from our joint venture interest in Carbones del Guasare (owner and operator of the Paso Diablo Mine in Venezuela). Carbones del Guasare incurred unfavorable results in 2009 compared to 2008 (our share of which was $25.6 million) due to lower productivity, higher operating costs and ongoing labor issues; in addition, we recognized a $34.7 million impairment loss on this investment. See Note 1 to our consolidated financial statements for additional information concerning this joint venture interest.

Lower net gains on disposal or exchange of assets ($49.7 million) was due primarily to a $54.0 million gain in the prior year from the sale of non-strategic coal reserves and surface lands located in Kentucky.

The above decreases to Corporate and Other Adjusted EBITDA were offset by lower costs associated with Btu Conversion activities ($16.9 million).

Interest expense was lower than prior year due to lower variable interest rates on our Term Loan Facility and accounts receivable securitization program and lower average borrowings on our Revolving Credit Facility.

Asset retirement obligation expense decreased in 2009 as compared to the prior year due primarily to a decrease in the ongoing and closed mine reclamation rates reflecting lower fuel and re-vegetation costs incurred in our Midwestern U.S. Mining segment.

Net Income Attributable to Common Stockholders

The following table presents net income attributable to common stockholders for the years ended December 31, 2009 and 2008:

	(Dollars in millions)		Increase (Decrease) to Income	
	2009	**2008**	**$**	**%**
		(Dollars in millions)		
Income from continuing operations before income taxes	$ 651.7	$ 1,179.3	$ (527.6)	(44.7)%
Income tax provision	(193.8)	(191.4)	(2.4)	(1.3)%
Income from continuing operations, net of income taxes	457.9	987.9	(530.0)	(53.6)%
Income (loss) from discontinued operations, net of income taxes	5.1	(28.8)	33.9	117.7%
Net income	463.0	959.1	(496.1)	(51.7)%
Net income attributable to noncontrolling interests	(14.8)	(6.2)	(8.6)	(138.7)%

Net income attributable to common stockholders	$ 448.2	$ 952.9	$ (504.7)	(53.0)%

Net income attributable to common stockholders decreased in 2009 compared to the prior year due to the decrease in income from continuing operations before incomes taxes discussed above.

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Income tax provision was impacted by the following:

Increased expense associated with the remeasurement of non-U.S. tax accounts as a result of the strengthening Australian dollar against the U.S dollar ($139.6 million; exchange rate rose 29% in 2009 compared to a 21% decrease in 2008, as illustrated below); and

	December 31,			Rate Change	
	2009	2008	2007	2009	2008
Australian dollar to U.S. dollar exchange rate	$ 0.8969	$ 0.6928	$ 0.8816	$ 0.2041	$ (0.1888)

The prior year release of a foreign valuation allowance related to our Australian net operating loss carry forwards ($45.3 million) as a result of significantly higher earnings resulting from the higher contract pricing that was secured during 2008.

The above increases to income tax expense were partially offset by lower pre-tax earnings in 2009, which drove a decrease to the income tax provision ($184.6 million).

Income from discontinued operations increased compared to the prior year as the prior year included operating losses, net of a $26.2 million gain on the sale of our Baralaba Mine, and an $11.7 million write-off of a coal excise tax receivable in the first quarter of 2008. In late 2008, legislation was passed which contained provisions that allowed for the refund of coal excise tax collected on certain coal shipments. In 2009, we received a coal excise tax refund resulting in approximately $35 million, net of income taxes, recorded in Income (loss) from discontinued operations, net of income taxes (see Note 2 to the consolidated financial statements for more information related to the excise tax refund). Partially offsetting the 2009 excise tax refund were operating losses associated with discontinued operations and assets held for sale ($20.6 million) and a $10.0 million loss on the sale of our Chain Valley Mine in Australia.

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

Summary

Higher average sales prices and volumes across all operating regions, particularly in Australia, contributed to an increase in revenues in 2008 compared to 2007. Segment Adjusted EBITDA rose primarily on the higher pricing mentioned above and favorable results from Trading and Brokerage. Increases in sales prices and volumes were partially offset by higher commodity, material, supply, sales-related and labor costs in all operating regions. Income from continuing operations, net of income taxes was $987.9 million in 2008, or $3.60 per diluted share, 123.7% above 2007 income from continuing operations, net of income taxes of $441.6 million, or $1.64 per diluted share.

Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		Increase	
	2008	2007	Tons	%
	(Tons in millions)			

Western U.S. Mining	169.7	161.4	8.3	5.1%
Midwestern U.S. Mining	30.7	29.6	1.1	3.7%
Australian Mining	23.4	20.4	3.0	14.7%
Trading and Brokerage	31.2	24.1	7.1	29.5%
Total tons sold	255.0	235.5	19.5	8.3%

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Revenues

The following table presents revenues for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2008	2007	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 2,533.1	$ 2,063.2	$ 469.9	22.8%
Midwestern U.S. Mining	1,154.6	987.1	167.5	17.0%
Australian Mining	2,242.8	1,117.6	1,125.2	100.7%
Trading and Brokerage	601.8	320.7	281.1	87.7%
Other	28.7	35.2	(6.5)	(18.5)%
Total revenues	$ 6,561.0	$ 4,523.8	$ 2,037.2	45.0%

Total revenues increased in 2008 compared to the prior year across all operating segments. The primary drivers of the increases included the following:

An increase in average sales price at our Australian Mining operations (75.0%), primarily driven by the strength of metallurgical coal prices on our Australian contracts that reprice annually in the second quarter of each year.

U.S. Mining operations average sales price increased over the prior year (15.2%) driven by the benefit of higher priced coal supply agreements signed in recent years.

Australia s volumes increased over the prior year (14.7%) from strong demand during the first three quarters of 2008 and additional production from recently completed mines. Year-over-year increases were partially offset by heavy rainfall and flooding in Queensland during the first quarter of 2008 and customer shipment deferrals in the fourth quarter of 2008 due to the global economic slowdown.

Increased demand also led to higher volumes across our U.S. operating segments, which overcame slightly lower volumes at some of our Midwestern U.S. Mining surface operations due to poor weather in that operating region that impacted production during the first and second quarters. The volume increase of 5.1% at our Western U.S. Mining operations resulted from greater throughput from capital improvements and contributions from our new El Segundo Mine, partially offset by the flooding in the midwestern U.S. that impacted railroad shipping performance related to western U.S. production during the second quarter of 2008.

Trading and Brokerage revenues increased over the prior year due to increased trading positions allowing us to capture market movements derived from the volatility of both domestic and international coal markets.

Also impacting year-over-year revenues in our Western U.S. Mining operations was an agreement to recover previously recognized postretirement healthcare and reclamation costs of $56.9 million in the second quarter of 2008.

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Segment Adjusted EBITDA

The following table presents segment Adjusted EBITDA for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2008	2007	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 681.3	$ 595.4	$ 85.9	14.4%
Midwestern U.S. Mining	177.3	200.0	(22.7)	(11.4)%
Australian Mining	1,016.6	167.2	849.4	508.0%
Trading and Brokerage	218.9	116.6	102.3	87.7%
Total Segment Adjusted EBITDA	$ 2,094.1	$ 1,079.2	$ 1,014.9	94.0%

Adjusted EBITDA from our Western U.S. Mining operations increased in 2008 over the prior year primarily driven by an overall increase in average sales prices per ton across the region ($2.10) and higher volumes in the region due to increased demand and greater throughput as a result of capital improvements. Also contributing to the increase was the recovery of postretirement healthcare and reclamation costs discussed above. Partially offsetting the pricing and volume contributions were higher per ton costs ($1.78). The cost increases were primarily due to higher sales related costs, higher material, supply and labor costs, higher repair and maintenance costs in the Powder River Basin and increased commodity costs, net of hedging activities, driven by higher average fuel and explosives pricing.

Midwestern U.S. Mining operations   Adjusted EBITDA decreased in 2008 as increases in average sales price per ton ($4.22) were offset by cost increases resulting from higher costs for commodities, net of hedging activities, driven by higher average fuel and explosives prices, as well as higher material, supply and labor costs. Heavy rains and flooding in the midwestern U.S. affected sales volume at some of our mines, particularly in the first half of the year. Also affecting the Midwestern U.S. Mining segment was the decrease in revenues from coal sold to synthetic fuel plants in the prior year ($28.9 million) due to the producers exiting the synthetic fuel market after expiration of federal tax credits at the end of 2007.

Our Australian Mining operations   Adjusted EBITDA increased in 2008 primarily due to higher pricing negotiated in the second quarter of 2008 ($41.06 per ton), higher overall volumes as a result of strong export demand and contributions from our recently completed mines and lower demurrage costs. These favorable impacts were partially offset by higher fuel costs, an increase in labor and overburden removal expenses and higher contractor costs (five of ten Australian mines are managed utilizing contract miners).

Trading and Brokerage Adjusted EBITDA increased in 2008 over the prior year due to increased trading volumes and higher coal price volatility.

Income From Continuing Operations Before Income Taxes

The following table presents income from continuing operations before income taxes for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		Increase (Decrease) to Income	
	2008	2007	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 2,094.1	$ 1,079.2	$ 1,014.9	94.0%
Corporate and Other Adjusted EBITDA	(247.2)	(109.5)	(137.7)	(125.8)%
Depreciation, depletion and amortization	(402.4)	(346.3)	(56.1)	(16.2)%
Asset retirement obligation expense	(48.2)	(23.7)	(24.5)	(103.4)%
Interest expense	(227.0)	(235.8)	8.8	3.7%
Interest income	10.0	7.0	3.0	42.9%
Income from continuing operations before income taxes	$ 1,179.3	$ 370.9	$ 808.4	218.0%

Income from continuing operations before income taxes increased over the prior year primarily due to the higher Total Segment Adjusted EBITDA discussed above, partially offset by lower Corporate and Other Adjusted EBITDA, higher depreciation, depletion and amortization, and higher asset retirement obligation expense.

The decrease in Corporate and Other Adjusted EBITDA during 2008 compared to 2007 was due to the following:

Higher selling and administrative expenses ($54.7 million) primarily driven by an increase in performance-based incentive costs and legal expenses;

Cost reimbursement and partner fees received in the prior year for the Prairie State project, primarily related to the entrance of new project partners ($29.5 million);

Lower net gains on disposals or exchanges of assets ($15.7 million). 2008 activity included a gain of $54.0 million on the sale of approximately 58 million tons of non-strategic coal reserves and surface lands located in Kentucky. 2007 activity included a gain of $50.5 million on the exchange of oil and gas rights and assets in more than 860,000 acres in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for coal reserves in West Virginia and Kentucky and cash proceeds. The prior year also included a gain of $26.4 million on the sale of approximately 172 million tons of coal reserves and surface lands to the Prairie State equity partners; and

Lower equity income ($15.5 million) from our joint venture interest in Carbones del Guasare (owner and operator of the Paso Diablo Mine in Venezuela) and higher costs associated with Btu Conversion activities of $14.3 million in 2008.

Depreciation, depletion and amortization was higher in 2008 compared to the prior year because of increased depletion across our operating platform resulting from the volume increases and the impact of mining higher value coal reserves. In addition, depreciation and depletion increases resulted from our recently completed Australian mines and depletion at our El Segundo Mine.

Asset retirement obligation expense increased in 2008 as compared to the prior year due to an increase in the ongoing and closed mine reclamation rates that reflect higher fuel, labor and re-vegetation costs, as well as an overall increase in the number of acres disturbed. The addition of the El Segundo Mine, which was completed in June 2008, also contributed to higher asset retirement obligation expense.

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Net Income Attributable to Common Stockholders

The following table presents net income attributable to common stockholders for the years ended December 31, 2008 and 2007:

	(Dollars in millions)		Increase (Decrease) to Income	
	2008	2007	$	%
		(Dollars in millions)		
Income from continuing operations before income taxes	$ 1,179.3	$ 370.9	$ 808.4	218.0%
Income tax (provision) benefit	(191.4)	70.7	(262.1)	(370.7)%
Income from continuing operations, net of income taxes	987.9	441.6	546.3	123.7%
Loss from discontinued operations, net of income taxes	(28.8)	(180.1)	151.3	84.0%
Net income	959.1	261.5	697.6	266.8%
Net (income) loss attributable to noncontrolling interests	(6.2)	2.3	(8.5)	(369.6)%
Net income attributable to common stockholders	$ 952.9	$ 263.8	$ 689.1	261.2%

Net income attributable to common stockholders increased in 2008 compared to the prior year due to the increase in income from continuing operations before incomes taxes discussed above.

Income tax provision was impacted by the following:

Increased expense in 2008 due to higher pre-tax earnings ($282.9 million); and

Valuation allowance release against federal net operating loss credits recognized into income in 2007 ($197.8 million); partially offset by

Income tax benefit associated with the remeasurement of non-U.S. tax accounts as a result of the weakening Australian dollar against the U.S dollar in 2008 ($121.2 million; exchange rate fell 21% in 2008 compared to an 11% increase in 2007, as illustrated below); and

	December 31,			Rate Change	
	2008	2007	2006	2008	2007
Australian dollar to U.S. dollar exchange rate	$ 0.6928	$ 0.8816	$ 0.7913	$ (0.1888)	$ 0.0903

The favorable rate difference resulting from higher foreign generated income in 2008 ($106.2 million); and

The release of a foreign valuation allowance against a portion of our Australian net operating loss carryforwards in 2008 ($45.3 million) as a result of significantly higher earnings resulting from the higher contract pricing that was secured during 2008.

Net income for 2008 was also impacted by a lower loss from discontinued operations as compared to the prior year due primarily to losses incurred for Patriot operations in 2007. The loss from discontinued operations for 2008 related to operating losses, net of a $26.2 million gain on the sale of our Baralaba Mine, and an $11.7 million write-off of an excise tax refund receivable (net of tax) as a result of an April 2008 U.S. Supreme Court ruling (see Note 2 to the consolidated financial statements).

Outlook

Near-Term Outlook

Global economies are showing signs of improvement, with 2010 economic forecasts estimating a 2.6 to 4.0% expansion although slower than expected economic improvement could temper these estimates. The

Asia-Pacific markets are expected to continue to outpace the U.S. and European markets in economic growth and therefore electricity generation and steel production. For 2009, China and India were the only steel producing majors to outpace prior-year levels, with all other nations 23% lower on average. For 2010, the World Steel Association estimates global steel production will increase 9 percent over 2009. Globally, 72 gigawatts of new coal-fueled generation are under construction and expected to come on line during 2010, more than 70% of which are new units in China and India. New global coal-fueled generation for 2010 is estimated to require approximately 300 million tons of new annual coal demand.

In the U.S., higher coal use caused by colder winter weather lowered utility stockpiles an estimated 25 to 30 million tons between December 2009 and mid-January 2010. As of February 15, 2010, utility stockpiles were approximately 150 to 155 million tons, 24% above the 10-year average and 6% above the year-ago level. We believe U.S. coal demand could rise 60 to 80 million tons based on economic growth, increasing industrial production and an expected reduction of coal-to-gas switching due to rising natural gas prices. Conversely, the Energy Information Administration (EIA) estimates coal production will be 43 million tons lower in 2010, in part due to production declines initiated in 2009. With rising demand and lower production, utility coal inventories are likely to be reduced.

As of January 26, 2010, we are targeting full-year 2010 production of approximately 185 to 195 million tons in the U.S. and 26 to 28 million tons in Australia. Total 2010 sales are expected to be in a range of 240 to 260 million tons. We may continue to adjust our production levels in response to changes in market demand.

We are fully contracted for 2010 at planned production levels in the U.S. As of January 26, 2010 we had 4.5 to 5.5 million tons of Australian metallurgical coal unpriced for 2010, along with 6.5 to 7.0 million tons of unpriced export thermal coal. Unpriced 2010 volumes are primarily planned for deliveries over the last three quarters of 2010.

We continue to manage costs and operating performance to mitigate external cost pressures, geologic conditions and potential shipping delays resulting from adverse port and rail performance. To mitigate the external cost pressures, we have an ongoing company-wide initiative to instill best practices at all operations. We may have higher per ton costs as a result of below-optimal production levels due to market-driven changes in demand. We may also encounter poor geologic conditions, lower third-party contract miner or brokerage performance or unforeseen equipment problems that limit our ability to produce at forecasted levels. To the extent upward pressure on costs exceeds our ability to realize sales increases, or if we experience unanticipated operating or transportation difficulties, our operating margins would be negatively impacted. See Cautionary Notice Regarding Forward-Looking Statements and Item 1A. of this report for additional considerations regarding our outlook.

We rely on ongoing access to the worldwide financial markets for capital, insurance, hedging and investments through a wide variety of financial instruments and contracts. To the extent these markets are not available or increase significantly in cost, this could have a negative impact on our ability to meet our business goals. Similarly, many of our customers and suppliers rely on the availability of the financial markets to secure the necessary financing and financial surety (letters of credit, performance bonds, etc.) to complete transactions with us. To the extent customers and suppliers are not able to secure this financial support, it could have a negative impact on our results of operations and/or counterparty credit exposure.

Long-Term Outlook

Our long-term global outlook remains positive. Coal has been the fastest-growing fuel in the world for each of the past six years, with consumption growing nearly twice as fast as total energy use.

The International Energy Agency s (IEA) World Energy Outlook estimates world primary energy demand will grow 40% between 2007 and 2030, with demand for coal rising 53%. China and India alone account for more than half of the expected incremental energy demand.

Coal is expected to retain its strong presence as a fuel for the power sector worldwide, with its share of the power generation mix projected to rise to 44% in 2030. Currently, 217 gigawatts of coal-fueled electricity generating plants are under construction around the world, representing more than 800 million tons of annual coal demand expected to come online in the next several years. In the U.S., 16 gigawatts of new coal-based generating capacity have been completed in 2009 or are under construction, representing approximately 65 million tons of annual coal demand when they come online over the next three to five years as expected.

We believe that Btu Conversion applications such as CTG and CTL plants represent an avenue for potential long-term industry growth. The EIA continues to project an increase in demand for unconventional sources of transportation fuel such as CTL, which is estimated to add nearly 70 million tons of annual U.S. coal demand by 2035. In addition, China and India are developing CTG and CTL facilities.

The IEA projects natural gas demand will grow 1.5% per year to just under 4,310 billion cubic meters in 2030. The biggest increase in absolute terms occurs in the Middle East, which holds the majority of the world s proven reserves, and non-OECD Asia. North America and Eastern Europe/Eurasia are expected to remain the leading gas consumers in 2030, even though their demand is expected to rise less in percentage terms than almost anywhere else globally. Globally, the share of renewables is projected to rise four percentage points to 22% between 2007 and 2030, with most of the growth coming from non-hydro sources. Nuclear power is expected to grow in all major regions with the exception of Europe, but its share in total generation is expected to fall between 2007 and 2030.

We continue to support clean coal technology development and other initiatives addressing global climate change through our participation in a number of projects in the U.S., China and Australia. In addition, clean coal technology development in the U.S. is being accelerated by funding under the American Recovery and Reinvestment Act of 2009 and by the formation of an Interagency Task Force on Carbon Capture and Storage to develop a comprehensive and coordinated federal strategy to speed the commercial development of clean coal technologies.

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 carbon capture and storage 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.

Liquidity and Capital Resources

Our primary sources of cash include sales of our coal production to customers, cash generated from our trading and brokerage activities, sales of non-core assets and financing transactions, including the sale of our accounts receivable (through our securitization program). Our primary uses of cash include our cash costs of coal production, capital expenditures, federal coal lease payments, interest costs and costs related to past mining obligations as well as acquisitions. Our ability to pay dividends, service our debt (interest and principal) and acquire new productive assets or businesses is dependent upon our ability to continue to generate cash from the primary sources noted above in excess of the primary uses. Future dividends and share repurchases, among other restricted items, are subject to limitations imposed in the covenants of our 5.875% and 6.875% Senior Notes and the Debentures. We generally fund all of our capital expenditure requirements with cash generated from operations.

We believe our available borrowing capacity and operating cash flows will be sufficient in the near term. As of December 31, 2009, we had cash and cash equivalents of $988.8 million and $1.5 billion of available borrowing capacity under our Senior Unsecured Credit Facility, net of outstanding letters of credit. The Senior Unsecured Credit

Facility matures on September 15, 2011.

The Pension Protection Act of 2006 (the Pension Protection Act), which was effective January 1, 2008, increased the long-term funding targets for single employer pension plans from 90% to 100%. At risk plans, as defined by the Pension Protection Act, are restricted from making full lump sum payments and from increasing benefits unless they are funded immediately, and also requires that the plan give participants notice regarding the at-risk status of the plan. If a plan falls below 60%, lump sum payments are prohibited and participant benefit accruals cease. As of December 31, 2009, our pension plans were approximately 77% funded, before considering planned 2010 contributions. Our minimum funding requirement for 2010 is approximately $3 million, and the qualified plans would not be considered at-risk. Using current assumptions, our 2011 minimum funding requirement would be approximately $98 million.

We also have a share repurchase program that has an available capacity of $700.4 million at December 31, 2009. While no repurchases were made in 2009 under the program, 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. The repurchase program does not have an expiration date and may be discontinued at any time.

Net cash provided by operating activities from continuing operations for 2009 decreased $356.3 million compared to the prior year primarily due to the decline in operating cash flows generated from our Australian mining operations on lower volumes and lower average pricing and the timing of cash flows from our working capital, primarily driven by foreign income tax payments related to prior year earnings.

The decrease in cash used in discontinued operations of $117.4 million was primarily due to approximately $59 million of cash received related to coal excise tax refunds in 2009 (see Note 2 to the consolidated financial statements for more information related to the excise tax refund) and lower current year payments related to Patriot discontinued operations.

Net cash used in investing activities from continuing operations decreased $11.1 million in 2009 compared to the prior year. The decrease primarily reflects lower federal coal lease expenditures of $54.9 million in 2009, partially offset by higher spending for our share of the Prairie State construction costs and additional investments in equity affiliates and joint venture projects in the prior year. Capital expenditures in 2009 were consistent with prior year as current year spending related to the development of our Bear Run Mine was offset by prior year spending related to the completion of our El Segundo Mine and expenditures for our blending and loadout facility at our North Antelope Rochelle Mine in the Western U.S.

Net cash used in financing activities decreased $384.7 million, primarily due to 2008 payments related to the repurchase of common stock ($199.8 million), the acquisition of noncontrolling interests relating to our Millennium Mine ($110.1 million) and payments on our revolving line of credit ($97.7 million). During 2009, we purchased $10.0 million face value of our 6.84% Series A bonds and $10.0 million face value of our 6.84% Series C bonds for a combined total of $19.0 million.

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Our total indebtedness as of December 31, 2009 and 2008 consisted of the following:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Term Loan under Senior Unsecured Credit Facility	$ 490.3	$ 490.3
Convertible Junior Subordinated Debentures due December 2066	371.5	369.9
7.375% Senior Notes due November 2016	650.0	650.0
6.875% Senior Notes due March 2013	650.0	650.0
7.875% Senior Notes due November 2026	247.1	247.0
5.875% Senior Notes due March 2016	218.1	218.1
6.84% Series C Bonds due December 2016	33.0	43.0
6.34% Series B Bonds due December 2014	15.0	18.0
6.84% Series A Bonds due December 2014		10.0
Capital lease obligations	67.5	81.2
Fair value hedge adjustment	8.4	15.1
Other	1.4	1.0
Total	$ 2,752.3	$ 2,793.6

We were in compliance with all of the covenants of the Senior Unsecured Credit Facility, the 6.875% Senior Notes, the 5.875% Senior Notes, the 7.375% Senior Notes, the 7.875% Senior Notes and the Debentures as of December 31, 2009.

Senior Unsecured Credit Facility. Our Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility and a $950.0 million Term Loan Facility. The Revolving Credit Facility is intended to accommodate working capital needs, letters of credit, the funding of capital expenditures and other general corporate purposes. The Revolving Credit Facility also includes a $50.0 million sub-facility available for same-day swingline loan borrowings.

Loans under the facility are available in U.S. dollars, with a sub-facility under the Revolving Credit Facility available in Australian dollars, pounds sterling and euros. Letters of credit under the Revolving Credit Facility are available to us in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and euros. The interest rate payable on the Revolving Credit Facility and the Term Loan Facility is based on a pricing grid tied to our leverage ratio, as defined in the Third Amended and Restated Credit Agreement. At December 31, 2009, the interest rate payable on the Revolving Credit Facility and the Term Loan Facility was LIBOR plus 0.75%, or a total of 1.0%.

We must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined in the Third Amended and Restated Credit Agreement. 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. The Senior Unsecured Credit Facility matures on September 15, 2011.

As of December 31, 2009, we had no borrowings and $315.7 million letters of credit outstanding under our Revolving Credit Facility.

Other Long-Term Debt. A description of our other debt instruments is described in Note 12 to the consolidated financial statements.

Third-party Security Ratings. The ratings for our Senior Unsecured Credit Facility and our Senior Unsecured Notes are as follows: Moody s has issued a Ba1 rating, Standard & Poor s a BB+ rating, and Fitch has issued a BB+ rating. The ratings on the Debentures are as follows: Moody s has issued a Ba3 rating, Standard & Poor s a B+ rating, and Fitch has issued a BB- rating. These security ratings reflected the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Shelf Registration Statement. On August 7, 2009, we filed an automatic shelf registration statement on Form S-3 as a well-known seasoned issuer with the SEC. The registration was for an indeterminate number of securities and is effective for three years, at which time we expect to be able to file an automatic shelf registration statement that would become immediately effective for another three-year term. Under this universal shelf registration statement, we have the capacity to offer and sell from time to time securities, including common stock, preferred stock, debt securities, warrants and units.

Capital Expenditures. Capital expenditures for 2010 are anticipated to be between $600 million to $650 million. The planned expenditures include sustaining capital at our existing mines, completion of our Bear Run Mine in western Indiana, expansion of our metallurgical and thermal coal export platform in Australia to serve the growth markets in Asia and funding of our Prairie State investment.

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2009:

		Payments Due By Year			
	Total	**Less than 1 Year**	**1 - 3 Years**	**3 - 5 Years**	**More than 5 Years**
			(Dollars in millions)		
Long-term debt obligations (principal and interest)	$ 5,219.5	$ 203.4	$ 884.8	$ 964.8	$ 3,166.5
Capital lease obligations (principal and interest)	80.3	15.1	30.2	35.0	
Operating lease obligations	468.1	96.4	153.6	100.3	117.8
Unconditional purchase obligations[1]	70.4	70.4			
Coal reserve lease and royalty obligations	79.9	11.3	16.8	15.0	36.8
Take or pay obligations[2]	1,864.4	110.7	297.4	310.4	1,145.9
Other long-term liabilities[3]	1,485.5	151.0	300.3	292.6	741.6
Total contractual cash obligations	$ 9,268.1	$ 658.3	$ 1,683.1	$ 1,718.1	$ 5,208.6

(1) We have purchase agreements with approved vendors for most types of operating expenses. However, our specific open purchase orders (which have not been recognized as a liability) under these purchase agreements, combined with any other open purchase orders, are not material. The commitments in the table above relate to capital purchases.

(2) Represents various long- and short-term take or pay arrangements associated with rail and port commitments for the delivery of coal, some of which extend to 2040, including amounts relating to export facilities currently under construction which are expected to be completed in 2010.

(3)

Represents long-term liabilities relating to our postretirement benefit plans, work-related injuries and illnesses, defined benefit pension plans and mine reclamation and end of mine closure costs.

As of December 31, 2009, we had $70.4 million of purchase obligations for capital expenditures and $0.9 million of obligations related to federal coal reserve lease payments due over the next five years. The purchase obligations for capital expenditures primarily relate to the replacement and improvement of equipment and facilities at existing mines.

We do not expect any of the $113.2 million of gross unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

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Off-Balance Sheet Arrangements

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

We use a combination of surety bonds, corporate guarantees (such as self bonds) and letters of credit to secure our financial obligations for reclamation, workers compensation, and coal lease obligations as follows as of December 31, 2009:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other[1]	Total
			(Dollars in millions)		
Self bonding	$ 821.9	$	$	$	$ 821.9
Surety bonds	772.3	116.3	8.7	57.3	954.6
Letters of credit	34.9		43.0	237.8	315.7
	$ 1,629.1	$ 116.3	$ 51.7	$ 295.1	$ 2,092.2

(1) Other includes the six letter of credit obligations described below and an additional $61.1 million in letters of credit and surety bonds related to collateral for surety companies, road maintenance, performance guarantees and other operations.

We own a 37.5% interest in Dominion Terminal Associates, a partnership that operates a coal export terminal in Newport News, Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The partners have severally (but not jointly) agreed to make payments under various agreements which in the aggregate provide the partnership with sufficient funds to pay rents and to cover the principal and interest payments on the floating-rate industrial revenue bonds issued by the Peninsula Ports Authority, and which are supported by letters of credit from a commercial bank. As of December 31, 2009, our maximum reimbursement obligation to the commercial bank was in turn supported by four letters of credit totaling $42.7 million.

We are party to an agreement with the Pension Benefit Guarantee Corporation (PBGC) and TXU Europe Limited, an affiliate of our former parent corporation, under which we are required to make special contributions to two of our defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If we or the PBGC give notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if we fail to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employee Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guarantee in place from TXU Europe Limited in favor of the PBGC before it draws on our letter of credit. On November 19, 2002 TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the U.S.) and continues under this process as of December 31, 2009. As a result of these proceedings, TXU Europe Limited may be liquidated or otherwise reorganized in such a way as to relieve it of its obligations under its guarantee.

At December 31, 2009, we have a $154.3 million letter of credit for collateral for bank guarantees issued with respect to certain reclamation and performance obligations related to some of our Australian mines.

Other Guarantees. See the Other Guarantees section of Note 19 to our consolidated financial statements for a description of our other guarantees.

Accounts Receivable Securitization Program. Under our accounts receivable securitization program in place at December 31, 2009, a pool of eligible trade receivables contributed to our wholly-owned, bankruptcy-remote subsidiary were sold, without recourse, to a multi-seller, asset-backed commercial paper conduit

(Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. We utilize proceeds from the sale of our accounts receivable as an alternative to other forms of debt, effectively reducing our overall borrowing costs. The funding cost of the securitization program was $4.0 million for the year ended December 31, 2009 and $10.8 million for the year ended December 31, 2008. The securitization program was renewed in May 2009 and amended in December 2009, and extends to May 2012, while the letter of credit commitment that supports the commercial paper facility underlying the securitization program must be renewed annually. The securitization transactions have been recorded as sales, with receivables sold to the Conduit removed from our consolidated balance sheets. The amount of interest in accounts receivable sold to the Conduit was $254.6 million as of December 31, 2009 and $275.0 million as of December 31, 2008 (see Note 6 to our consolidated financial statements for additional information on our accounts receivable securitization program). On January 25, 2010, the receivables purchase agreement for the accounts receivable securitization program was amended and restated to add a second multi-seller asset-backed commercial paper conduit as a purchaser.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with GAAP. GAAP requires that we make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

Employee-Related Liabilities. We have long-term liabilities for our employees postretirement benefit costs and defined benefit pension plans. Detailed information related to these liabilities is included in Notes 14 and 15 to our consolidated financial statements. Liabilities for postretirement benefit costs and workers compensation obligations are not funded. Our pension obligations are funded in accordance with the provisions of applicable law. Expense for the year ended December 31, 2009 for the pension and postretirement liabilities totaled $76.8 million, while funding payments were $110.3 million.

Each of 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 make 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 could increase our obligation to satisfy these or additional obligations. For our postretirement health care liability, assumed discount rates and health care cost trend rates have a significant effect on the expense and liability amounts reported for health care plans. Below we have provided two separate sensitivity analyses to demonstrate the significance of these assumptions in relation to reported amounts.

Health care cost trend rate:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components[1]	$ 6.7	$ (5.7)
Effect on total postretirement benefit obligation[1]	$ 98.3	$ (84.6)

Discount rate:

	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components[1]	$ 0.6	$ (0.6)
Effect on total postretirement benefit obligation[1]	$ (46.1)	$ 52.2

(1) In addition to the effect on total service and interest cost components of expense, changes in trend and discount rates would also increase or decrease the actuarial gain or loss amortization expense component. The gain or loss amortization would approximate the increase or decrease in the obligation divided by 10.92 years at December 31, 2009.

Asset Retirement Obligations. 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 applicable reclamation laws in the U.S. and Australia as defined by each mining permit. Asset retirement 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. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the reclamation activities), the obligation and asset are revised to reflect the new estimate after applying the appropriate credit-adjusted, risk-free rate. 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. Asset retirement obligation expense for the year ended December 31, 2009 was $40.1 million, and payments totaled $12.4 million. See Note 13 to our consolidated financial statements for additional details regarding our asset retirement obligations.

Income Taxes. We account for income taxes in accordance with accounting guidance which requires deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In our annual evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in our annual evaluation of our valuation allowance, we may record a change in valuation allowance through income tax expense in the period such determination is made.

Our liability for unrecognized tax benefits contains uncertainties because management is required to make assumptions and to apply judgment to estimate the exposures associated with our various filing positions. We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position must be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. We believe that the judgments and estimates are reasonable; however, actual results could differ.

Level 3 Fair Value Measurements. In accordance with the Fair Value Measurements and Disclosures topic of the Financial Accounting Standards Board Accounting Standards Codification, we evaluate the quality and reliability of the assumptions and data used to measure fair value in the three hierarchy Levels 1, 2 and 3 (see Note 3 to our consolidated financial statements for additional information). Commodity swaps and options and physical commodity purchase/sale contracts transacted in less liquid markets or contracts, such as long-term arrangements, with limited price availability were classified in Level 3. Indicators of less liquid markets are those with periods of low trade activity or when broker quotes reflect wide pricing spreads. Generally, these instruments or contracts are valued using internally generated models that include forward pricing curve quotes from one to three reputable brokers. Our valuation techniques also include basis adjustments for heat rate, sulfur and ash content, port and freight costs, and credit and nonperformance risk. We validate our valuation inputs with third-party information and settlement prices from other sources where available. We also consider credit and nonperformance risk in the fair value measurement by analyzing the counterparty s exposure balance, credit rating and average default rate, net of any counterparty credit enhancements (e.g., collateral), as well as our own credit rating for financial derivative liabilities.

We have consistently applied these valuation techniques in all periods presented, and believe we have obtained the most accurate information reasonably available for the types of derivative contracts held. Valuation changes from period to period for each level will increase or decrease depending on: (i) the relative change in fair value for positions held, (ii) new positions added, (iii) realized amounts for completed trades, and (iv) transfers between levels. Our coal trading strategies utilize various swaps and derivative physical contracts. Periodic changes in fair value for purchase and sale positions, which are executed to lock in coal trading spreads, occur in each level and therefore the overall change in value of our coal-trading platform requires consideration of valuation changes across all levels.

At December 31, 2009, 5% of our net financial assets were categorized as Level 3. At December 31, 2008, the percentage of Level 3 net financial assets compared to the total net financial liabilities is not meaningful due to the overall liability position at December 31, 2008. See Note 3 to our consolidated financial statements for additional information regarding fair value measurements.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

See Note 1 to our consolidated financial statements for a discussion of newly adopted accounting pronouncements and accounting pronouncements not yet implemented.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The potential for changes in the market value of our coal and freight trading, emission allowances, crude oil, diesel fuel, natural gas, explosives, interest rate and currency portfolios is referred to as market risk. Market risk related to our coal trading and freight portfolio is evaluated using a value at risk (VaR) analysis. VaR analysis is not used to evaluate our non-trading interest rate, diesel fuel, explosives or currency hedging portfolios. A description of each market risk category is set forth below. We attempt to manage market risks through diversification, controlling position sizes and executing hedging strategies. Due to lack of quoted market prices and the long-term, illiquid nature of the positions, we have not quantified market risk related to our non-trading, long-term coal supply agreement portfolio.

Coal Trading Activities and Related Commodity Price Risk

We engage in over-the-counter, direct and brokered trading of coal, ocean freight and fuel-related commodities to support our coal trading related activities (coal trading). These activities give rise to commodity price risk, which represents the potential loss that can be caused by an adverse change in the market value of a particular commitment. We actively measure, monitor and adjust traded position levels to remain within risk limits prescribed by management. For example, we have policies in place that limit the amount of total exposure, as measured by VaR, that we may assume at any point in time.

We account for coal trading using the fair value method, which requires us to reflect financial instruments with third parties at market value in our consolidated financial statements. Our trading portfolio included forwards, swaps and options as of December 31, 2009 and 2008.

We perform a VaR analysis on our coal trading portfolio, which includes bilaterally-settled and exchange-settled over-the-counter and brokerage coal trading. The use of VaR allows us to quantify in dollars, on a daily basis, a measure of price risk inherent in our trading portfolio. VaR represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon (liquidation period) within a specified confidence level. Our VaR model is based on a variance/co-variance approach. This captures our exposure related to forwards, swaps and options positions. Our VaR model assumes a 5 to 15-day holding period and a 95% one-tailed confidence interval. This means that there is a one in 20 statistical chance that the portfolio would lose more than the VaR estimates during the liquidation period. Our volatility calculation incorporates an exponentially weighted moving average algorithm based on the previous 60 market days, which makes our volatility more representative of recent market conditions, while still reflecting an awareness of historical price movements. VaR does not capture the loss expected in the 5% of the time the portfolio value exceeds measured VaR.

The use of VaR allows us to aggregate pricing risks across products in the portfolio, compare risk on a consistent basis and identify the drivers of risk. We use historical data to estimate price volatility as an input to VaR. Given our reliance on historical data, we believe VaR is reasonably effective in characterizing risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. Due to the subjectivity in the choice of the liquidation period, reliance on historical data to calibrate the models and the inherent limitations in the VaR methodology, we perform regular stress and scenario analyses to estimate the impacts of market changes on the value of the portfolio. Additionally, back-testing is regularly performed to monitor the effectiveness of our VaR measure. The results of these analyses are used to supplement the VaR methodology and identify additional market-related risks. An inherent limitation of VaR is that past changes in market risk factors may not produce accurate predictions of future market risk.

During the year ended December 31, 2009, the actual low, high, and average VaR for our coal trading portfolio were \$2.7 million, \$15.9 million, and \$8.7 million, respectively. Our VaR decreased over the prior year due to less price volatility and lower overall prices in the U.S. and international coal markets.

As of December 31, 2009, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	**Percentage of Portfolio Total**
2010	46%
2011	51%
2012	3%
	100%

We also monitor other types of risk associated with our coal trading activities, including credit, market liquidity and counterparty nonperformance.

Nonperformance and Credit Risk

The fair value of our assets and liabilities reflect adjustments for nonperformance and credit risk. Our concentration of nonperformance and credit risk is substantially with electric utilities, steel producers, energy producers and energy marketers. Our policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to regularly monitor the credit extended. If we engage in a transaction with a counterparty that does not meet our credit standards, we seek to protect our position by requiring the counterparty to provide an appropriate credit enhancement. Also, when appropriate (as determined by our credit management function), we have taken steps to reduce our exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of a failure to pay or perform. To reduce our credit exposure related to trading and brokerage activities, we seek to enter into netting agreements with counterparties that permit us to offset receivables and payables with such counterparties and, to the extent required, will post or receive margin amounts associated with exchange-cleared positions.

We conduct our various hedging activities related to foreign currency, interest rate, and fuel and explosives exposures with a variety of highly-rated commercial banks. In light of the recent turmoil in the financial markets, we continue to closely monitor counterparty creditworthiness.

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Foreign Currency Risk

We utilize currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 3 to our consolidated financial statements. Assuming we had no hedges in place, our exposure in operating costs and expenses due to a $0.05 change in the Australian dollar/U.S. dollar exchange rate is approximately $82 million for 2010. However, taking into consideration hedges currently in place, our net exposure to the same rate change is approximately $17 million for 2010. The chart at the end of Item 7A shows the notional amount of our hedge contracts as of December 31, 2009.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. To achieve these objectives, we manage fixed-rate debt as a percent of net debt through the use of various hedging instruments, which are discussed in detail in Note 3 to our consolidated financial statements. As of December 31, 2009, after taking into consideration the effects of interest rate swaps, we had $2.4 billion of fixed-rate borrowings and $0.4 billion of variable-rate borrowings outstanding. A one percentage point increase in interest rates would result in an annualized increase to interest expense of approximately $4.2 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $130 million in the estimated fair value of these borrowings.

Other Non-trading Activities   Commodity Price Risk

Long-term Coal Contracts. We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements (those with terms longer than one year), rather than through the use of derivative instruments. We sold 93% and 90% of our worldwide sales volume under long-term coal supply agreements during 2009 and 2008, respectively. We are fully contracted for 2010 at planned production levels in the U.S. We had 11 to 12.5 million tons remaining to be priced for 2010 in Australia at January 26, 2010.

Diesel Fuel and Explosives Hedges. We manage commodity price risk of the diesel fuel and explosives used in our mining activities through the use of fixed price contracts, cost-plus contracts and a combination of forward contracts with our suppliers and financial derivative contracts, which are primarily swap contracts with financial institutions.

Notional amounts outstanding under fuel-related, derivative swap contracts are noted in the chart at the end of Item 7A. We expect to consume 130 to 135 million gallons of diesel fuel in 2010. Assuming we had no hedges in place, a $10 per barrel change in the price of crude oil (the primary component of a refined diesel fuel product) would increase or decrease our annual diesel fuel costs by approximately $31 million based on our expected usage. However, taking into consideration hedges currently in place, our net exposure to changes in the price of crude oil is approximately $14 million.

Notional amounts outstanding under explosives-related swap contracts are noted in the chart at the end of Item 7A. We expect to consume 345,000 to 355,000 tons of explosives during 2010 in the U.S. Explosives costs in Australia are generally included in the fees paid to our contract miners. Assuming we had no hedges in place, a price change in natural gas (often a key component in the production of explosives) of one dollar per million MMBtu would result in an increase or decrease in our annual explosives costs of approximately $6 million based on our expected usage. However, taking into consideration hedges currently in place, our net exposure to changes in the price of natural gas is approximately $3 million.

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Notional Amounts and Fair Value. The following summarizes our interest rate, foreign currency and commodity positions at December 31, 2009:

	Notional Amount by Year of Maturity						
	Total	2010	2011	2012	2013	2014	2015 and thereafter
Interest Rate Swaps							
Fixed-to-floating (dollars in millions)	$ 50.0	$	$	$	$ 50.0	$	$
Floating-to-fixed (dollars in millions)	$ 120.0	$	$ 120.0	$	$	$	$
Foreign Currency							
A$:US$ hedge contracts (A$ millions)	$ 3,291.7	$ 1,299.3	$ 994.8	$ 742.6	$ 120.0	$ 135.0	$
Commodity Contracts							
Diesel fuel hedge contracts (million gallons)	177.8	71.1	65.3	41.4			
U.S. explosives hedge contracts (million MMBtu)	3.0	3.0					

	Account Classification by			
	Cash flow hedge	Fair value hedge	Economic hedge	Fair Value Asset (Liability) (Dollars in millions)
Interest Rate Swaps				
Fixed-to-floating (dollars in millions)	$	$ 50.0	$	$ 1.5
Floating-to-fixed (dollars in millions)	$ 120.0	$	$	$ (9.8)
Foreign Currency				
A$:US$ hedge contracts (A$ millions)	$ 3,291.7	$	$	$ 206.1
Commodity Contracts				
Diesel fuel hedge contracts (million gallons)	177.8			$ (22.2)
U.S. explosives hedge contracts (million MMBtu)	3.0			$ (4.8)

Item 8. ***Financial Statements and Supplementary Data.***

See Part IV, Item 15 of this report for information required by this Item, which information is incorporated by reference herein.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures are designed to, among other things, provide reasonable assurance that material information, both financial and non-financial, and other information required under the securities laws to be disclosed is accumulated and communicated to senior management, including the principal executive officer and principal financial officer, on a timely basis. As of December 31, 2009, the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of December 31,

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2009, and concluded that such controls and procedures are effective to provide reasonable assurance that the desired control objectives were achieved.

Changes in Internal Control Over Financial Reporting

We periodically review our internal control over financial reporting as part of our efforts to ensure compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. In addition, we routinely review our system of internal control over financial reporting to identify potential changes to our processes and systems that may improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new systems, consolidating the activities of acquired business units, migrating certain processes to our shared services organizations, formalizing and refining policies and procedures, improving segregation of duties and adding monitoring controls. In addition, when we acquire new businesses, we incorporate our controls and procedures into the acquired business as part of our integration activities. There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. Our internal control framework and processes were designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on this assessment, management concluded that the Company s internal control over financial reporting were effective to provide reasonable assurance that the desired control objectives were achieved as of December 31, 2009.

Our Independent Registered Public Accounting Firm, Ernst & Young LLP, has audited our internal control over financial reporting, as stated in their unqualified opinion report included herein.

/s/ Gregory H. Boyce	/s/ Michael C. Crews
Gregory H. Boyce Chairman and Chief Executive Officer	Michael C. Crews Executive Vice President and Chief Financial Officer

February 24, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited Peabody Energy Corporation s (the Company s) internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Peabody Energy Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Peabody Energy Corporation as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2009, and our report dated February 24, 2010, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 24, 2010

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Item 9B. *Other Information.*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by Item 401 of Regulation S-K is included under the caption Election of Directors-Director Qualifications in our 2010 Proxy Statement and in Part I of this report under the caption Executive Officers of the Company. The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions Ownership of Company Securities Section 16(a) Beneficial Ownership Reporting Compliance, Corporate Governance Matters and Information Regarding Board of Directors and Committees-Committees of the Board of Directors-Audit Committee in our 2010 Proxy Statement. Such information is incorporated herein by reference.

Item 11. *Executive Compensation.*

The information required by Items 402 and 407 (e)(4) and (e)(5) of Regulation S-K is included under the captions Executive Compensation, Compensation Committee Interlocks and Insider Participation and Report of the Compensation Committee in our 2010 Proxy Statement and is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information required by Items 403 of Regulation S-K is included under the caption Ownership of Company Securities in our 2010 Proxy Statement and is incorporated herein by reference.

Equity Compensation Plan Information

As required by Item 201(d) of regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2009:

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved			

by security holders	1,715,557	$ 20.78	14,588,584
Equity compensation plans not approved by security holders			
Total	1,715,557	$ 20.78	14,588,584

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions Policy for Approval of Related Person Transactions and Information Regarding Board of Directors and Committees-Director Independence in our 2010 Proxy Statement and is incorporated herein by reference.

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Item 14. ***Principal Accounting Fees and Services.***

The information required by Item 9(e) of Schedule 14A is included under the caption Fees Paid to Independent Registered Public Accounting Firm in our 2010 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. ***Exhibit, Financial Statement Schedules.***

(a) Documents Filed as Part of the Report

(1) Financial Statements.

The following consolidated financial statements of Peabody Energy Corporation are included herein on the pages indicated:

(2) Financial Statement Schedule.

The following financial statement schedule of Peabody Energy Corporation and the report thereon of the independent registered public accounting firm are at the pages indicated:

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and, therefore, have been omitted.

(3) Exhibits.

See Exhibit Index hereto.

Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the Company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the Company and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Securities and Exchange Commission upon request.

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SIGNATURES

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

PEABODY ENERGY CORPORATION

/s/ GREGORY H. BOYCE
Gregory H. Boyce
Chairman and Chief Executive Officer

Date: February 24, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons, on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ GREGORY H. BOYCE Gregory H. Boyce	Chairman and Chief Executive Officer, Director (principal executive officer)	February 24, 2010
/s/ MICHAEL C. CREWS Michael C. Crews	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 24, 2010
/s/ WILLIAM A. COLEY William A. Coley	Director	February 24, 2010
/s/ WILLIAM E. JAMES William E. James	Director	February 24, 2010
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 24, 2010
/s/ M. FRANCES KEETH M. Frances Keeth	Director	February 24, 2010
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 24, 2010
/s/ ROBERT A. MALONE	Director	February 24, 2010

Robert A. Malone		
/s/ WILLIAM C. RUSNACK	Director	February 24, 2010
William C. Rusnack		

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Signature	Title	Date
/s/ JOHN F. TURNER John F. Turner	Director	February 24, 2010
/s/ SANDRA VAN TREASE Sandra Van Trease	Director	February 24, 2010
/s/ ALAN H. WASHKOWITZ Alan H. Washkowitz	Director	February 24, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2009, the Company changed its method for accounting for noncontrolling interests, its method for accounting for convertible debt that may be settled in cash upon conversion, and its method for accounting for earnings per share under the two-class method, and on January 1, 2008, the Company changed its method of accounting for the recognition of derivative positions with the same counterparty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Peabody Energy Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 24, 2010, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 24, 2010

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions, except per share data)		
Revenues			
Sales	$ 5,468.1	$ 6,004.0	$ 4,313.9
Other revenues	544.3	557.0	209.9
Total revenues	6,012.4	6,561.0	4,523.8
Costs and expenses			
Operating costs and expenses	4,467.7	4,585.2	3,510.1
Depreciation, depletion and amortization	405.2	402.4	346.3
Asset retirement obligation expense	40.1	48.2	23.7
Selling and administrative expenses	208.7	201.8	147.1
Other operating (income) loss:			
Net gain on disposal or exchange of assets	(23.2)	(72.9)	(88.6)
(Income) loss from equity affiliates	69.1		(14.5)
Operating profit	844.8	1,396.3	599.7
Interest expense	201.2	227.0	235.8
Interest income	(8.1)	(10.0)	(7.0)
Income from continuing operations before income taxes	651.7	1,179.3	370.9
Income tax provision (benefit)	193.8	191.4	(70.7)
Income from continuing operations, net of income taxes	457.9	987.9	441.6
Income (loss) from discontinued operations, net of income taxes	5.1	(28.8)	(180.1)
Net income	463.0	959.1	261.5
Less: Net income (loss) attributable to noncontrolling interests	14.8	6.2	(2.3)
Net income attributable to common stockholders	$ 448.2	$ 952.9	$ 263.8
Income From Continuing Operations			
Basic earnings per share	$ 1.66	$ 3.63	$ 1.67
Diluted earnings per share	$ 1.64	$ 3.60	$ 1.64
Net Income Attributable to Common Stockholders			
Basic earnings per share	$ 1.68	$ 3.52	$ 0.99
Diluted earnings per share	$ 1.66	$ 3.50	$ 0.97

Dividends declared per share	$	0.25	$	0.24	$	0.24

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(Amounts in millions, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 988.8	$ 449.7
Accounts receivable, net of allowance for doubtful accounts of $18.3 at December 31, 2009 and $24.8 at December 31, 2008	303.0	382.2
Inventories	325.1	276.2
Assets from coal trading activities, net	276.8	662.8
Deferred income taxes	40.0	1.7
Other current assets	255.3	198.7
Total current assets	2,189.0	1,971.3
Property, plant, equipment and mine development		
Land and coal interests	7,557.3	7,349.4
Buildings and improvements	908.0	858.1
Machinery and equipment	1,391.2	1,245.1
Less: accumulated depreciation, depletion and amortization	(2,595.0)	(2,155.3)
Property, plant, equipment and mine development, net	7,261.5	7,297.3
Investments and other assets	504.8	427.0
Total assets	$ 9,955.3	$ 9,695.6
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 14.1	$ 17.0
Liabilities from coal trading activities, net	110.6	304.2
Accounts payable and accrued expenses	1,187.7	1,535.0
Total current liabilities	1,312.4	1,856.2
Long-term debt, less current maturities	2,738.2	2,776.6
Deferred income taxes	299.1	20.8
Asset retirement obligations	452.1	418.7
Accrued postretirement benefit costs	914.1	766.1
Other noncurrent liabilities	483.5	737.7
Total liabilities	6,199.4	6,576.1
Stockholders equity		

Preferred Stock $0.01 per share par value; 10,000,000 shares authorized, no shares issued or outstanding as of December 31, 2009 or December 31, 2008				
Series A Junior Participating Preferred Stock 1,500,000 shares authorized, no shares issued or outstanding as of December 31, 2009 or December 31, 2008				
Perpetual Preferred Stock 750,000 shares authorized, no shares issued or outstanding as of December 31, 2009 or December 31, 2008				
Series Common Stock $0.01 per share par value; 40,000,000 shares authorized, no shares issued or outstanding as of December 31, 2009 or December 31, 2008				
Common Stock $0.01 per share par value; 800,000,000 shares authorized, 276,848,279 shares issued and 268,203,815 shares outstanding as of December 31, 2009 and 275,211,240 shares issued and 266,644,979 shares outstanding as of December 31, 2008		2.8		2.8
Additional paid-in capital		2,067.7		2,020.2
Retained earnings		2,183.8		1,802.4
Accumulated other comprehensive loss		(183.5)		(388.5)
Treasury shares, at cost: 8,644,464 shares as of December 31, 2009 and 8,566,261 shares as of December 31, 2008		(321.1)		(318.8)
Peabody Energy Corporation s stockholders equity		3,749.7		3,118.1
Noncontrolling interests		6.2		1.4
Total stockholders equity		3,755.9		3,119.5
Total liabilities and stockholders equity	$	9,955.3	$	9,695.6

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2009	2008	2007
	(Dollars in millions)		
Cash Flows From Operating Activities			
Net income	$ 463.0	$ 959.1	$ 261.5
(Income) loss from discontinued operations, net of income taxes	(5.1)	28.8	180.1
Income from continuing operations, net of income taxes	457.9	987.9	441.6
Adjustments to reconcile income from continuing operations, net of income taxes to net cash provided by operating activities:			
Depreciation, depletion and amortization	405.2	402.4	346.3
Deferred income taxes	131.1	(33.3)	(196.5)
Share-based compensation	38.8	34.9	20.1
Amortization of debt discount and debt issuance costs	7.8	7.7	8.0
Net gain on disposal or exchange of assets	(23.2)	(72.9)	(88.6)
(Income) loss from equity affiliates	69.1		(14.5)
Revenue recovery on coal supply agreement		(56.9)	
Dividends received from equity affiliates		19.9	12.9
Changes in current assets and liabilities:			
Accounts receivable, including securitization	81.4	(114.7)	65.6
Inventories	(48.9)	(13.2)	(60.9)
Net assets from coal trading activities	70.9	(43.0)	(77.6)
Other current assets	(3.3)	1.9	(57.1)
Accounts payable and accrued expenses	(123.8)	235.1	52.6
Asset retirement obligations	27.7	32.9	13.6
Workers compensation obligations	3.0	10.3	2.7
Accrued postretirement benefit costs	7.2	13.6	13.1
Contributions to pension plans	(38.7)	(21.3)	(5.4)
Other, net	(8.7)	18.5	(15.2)
Net cash provided by continuing operations	1,053.5	1,409.8	460.7
Net cash used in discontinued operations	(5.6)	(123.0)	(141.3)
Net cash provided by operating activities	1,047.9	1,286.8	319.4
Cash Flows From Investing Activities			
Additions to property, plant, equipment and mine development	(260.6)	(264.1)	(438.8)
Investment in Prairie State Energy Campus	(56.8)	(40.9)	(28.8)
Federal coal lease expenditures	(123.6)	(178.5)	(178.2)
Proceeds from disposal of assets, net of notes receivable	53.9	72.8	119.6
Additions to advance mining royalties	(6.1)	(6.0)	(8.1)
Investments in equity affiliates and joint ventures	(15.0)	(2.6)	(4.6)

Net cash used in continuing operations	(408.2)	(419.3)	(538.9)
Net cash provided by (used in) discontinued operations	1.7	23.9	(36.4)
Net cash used in investing activities	(406.5)	(395.4)	(575.3)
Cash Flows From Financing Activities			
Change in revolving line of credit		(97.7)	97.7
Payments of long-term debt	(37.1)	(32.7)	(117.8)
Common stock repurchase		(199.8)	
Dividends paid	(66.8)	(64.9)	(63.7)
Payment of debt issuance costs			(0.8)
Excess tax benefit related to stock options exercised			96.7
Proceeds from stock options exercised	3.6	14.1	26.2
Net proceeds from borrowing	0.8		
Acquisition of noncontrolling interests (Millennium Mine)		(110.1)	
Other, net	(2.8)	4.1	3.4
Net cash provided by (used in) continuing operations	(102.3)	(487.0)	41.7
Net cash used in discontinued operations			(67.0)
Net cash used in financing activities	(102.3)	(487.0)	(25.3)
Net change in cash and cash equivalents	539.1	404.4	(281.2)
Cash and cash equivalents at beginning of year	449.7	45.3	326.5
Cash and cash equivalents at end of year	$ 988.8	$ 449.7	$ 45.3

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

	Peabody Energy Corporation s Stockholders Equity						
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Stockholders Equity
	(Dollars in millions)						
December 31, 2006	$ 2.7	$ 1,788.0	$ (103.7)	$ 1,115.9	$ (249.2)	$ 33.3	$ 2,587.0
Comprehensive income:							
Net income				263.8		(2.3)	261.5
Increase in fair value of cash flow hedges (net of $14.5 tax provision)					21.9		21.9
Postretirement plans and workers compensation obligations (net of $50.2 tax provision)					87.2		87.2
Comprehensive income				263.8	109.1	(2.3)	370.6
Dividends paid				(63.7)			(63.7)
Patriot Coal Corporation spin-off				(375.1)	73.0	(14.1)	(316.2)
Share-based compensation		48.8					48.8
Stock options exercised		26.2					26.2
Employee stock purchases		6.4					6.4
Shares relinquished			(4.3)				(4.3)
Income tax benefits from stock options exercised		96.7					96.7
Noncontrolling interests activity related to discontinued operations						(6.2)	(6.2)
Acquisition of noncontrolling interests associated with Excel Coal Limited - purchase accounting adjustment						(7.0)	(7.0)
Distributions to noncontrolling interests						(3.0)	(3.0)
December 31, 2007	$ 2.7	$ 1,966.1	$ (108.0)	$ 940.9	$ (67.1)	$ 0.7	$ 2,735.3
Comprehensive income:							
Net income				952.9		6.2	959.1
Decrease in fair value of cash flow hedges (net of $178.2					(217.9)		(217.9)

tax benefit)							
Postretirement plans and workers compensation obligations (net of $59.3 tax benefit)					(103.5)		(103.5)
Comprehensive income				952.9	(321.4)	6.2	637.7
Dividends paid				(64.9)			(64.9)
Patriot Coal Corporation spin-off adjustment				(26.5)			(26.5)
Share-based compensation		34.9					34.9
Stock options exercised	0.1	14.0					14.1
Employee stock purchases		5.2					5.2
Shares relinquished			(11.0)				(11.0)
Common stock repurchased			(199.8)				(199.8)
Distributions to noncontrolling interests						(1.1)	(1.1)
Eliminations of noncontrolling interests due to acquisitions						(4.4)	(4.4)
December 31, 2008	$ 2.8	$ 2,020.2	$ (318.8)	$ 1,802.4	$ (388.5)	$ 1.4	$ 3,119.5
Comprehensive income:							
Net income				448.2		14.8	463.0
Increase in fair value of cash flow hedges (net of $220.9 tax provision)					319.8		319.8
Postretirement plans and workers compensation obligations (net of $71.8 tax benefit)					(114.8)		(114.8)
Comprehensive income				448.2	205.0	14.8	668.0
Dividends paid				(66.8)			(66.8)
Share-based compensation		38.8					38.8
Stock options exercised		3.6					3.6
Employee stock purchases		5.1					5.1
Shares relinquished			(2.3)				(2.3)
Distributions to noncontrolling interests						(10.0)	(10.0)
December 31, 2009	$ 2.8	$ 2,067.7	$ (321.1)	$ 2,183.8	$ (183.5)	$ 6.2	$ 3,755.9

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (the Company) and its affiliates. All intercompany transactions, profits and balances have been eliminated in consolidation.

Description of Business

The Company is engaged in the mining of thermal coal for sale primarily to electric utilities and metallurgical coal for sale to industrial customers. The Company s mining operations are located in the United States (U.S.) and Australia, and include an equity interest in a mining operation in Venezuela. In addition to the Company s mining operations, the Company markets, brokers and trades coal. The Company s other energy related commercial activities include participating in the development of mine-mouth coal-fueled generating plants, the management of its vast coal reserve and real estate holdings, and the development of Btu Conversion and clean coal technologies. The Company s Btu Conversion projects are designed to expand the uses of coal through various technologies such as coal-to-liquids and coal gasification.

Newly Adopted Accounting Standards

In August 2009, the Financial Accounting Standards Board (FASB) issued accounting guidance that clarifies the fair value measurement of liabilities in circumstances in which a quoted price in an active market for the identical liability is not available. In those circumstances, an entity is required to measure fair value utilizing one or more of the following techniques: (1) a valuation technique that uses the quoted market price of an identical liability or similar liabilities when traded as assets; or (2) another valuation technique that is consistent with the principles of Accounting Standards Codification (ASC) Topic 820, such as a present value technique or market approach. The guidance also clarifies that when estimating the fair value liability, a reporting entity is not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of a liability. Additionally, the guidance clarifies that both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required are Level 1 fair value measurements. The guidance, which became effective in the fourth quarter of 2009, did not have a material impact on the Company s results of operations or financial condition.

In May 2009, the FASB issued an accounting standard that was effective upon issuance that establishes accounting and disclosure guidance for subsequent events, which are events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company evaluated subsequent events after the balance sheet date of December 31, 2009 through the filing of this report with the Securities and Exchange Commission on February 24, 2010.

In April 2009, the FASB issued an accounting standard which requires disclosures of the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not on a company s balance sheet, in interim reporting periods and in financial statements for annual reporting periods. A related standard was also issued in April 2009 which requires entities to disclose the methods and significant assumptions used to estimate the fair value of financial instruments and describe changes in methods and significant assumptions, in both interim and annual financial statements. The Company adopted the standards on June 30, 2009. See Note 3 for further information.

In April 2009, the FASB issued an accounting standard which provides additional guidance for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased. The standard also includes guidance on identifying circumstances that indicate a transaction is not orderly and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

requires that a reporting entity: (1) disclose in interim and annual periods the inputs and valuation technique(s) used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, during the period, and (2) define the major category for any equity securities and debt securities to be based on the major security types (nature and risk of the security). The Company adopted the standard on June 30, 2009. While adoption of the standard had an impact on the Company s disclosures, it did not affect the Company s results of operations or financial condition.

In December 2008, the FASB issued an accounting standard to provide for additional transparency on an employer s disclosures about plan assets of a defined benefit pension or other postretirement plan, including the concentrations of risk in those plans. The Company adopted the standard on December 31, 2009. While the adoption of this guidance had an impact on the Company s disclosures, it did not affect the Company s results of operations, financial condition or cash flows.

In June 2008, the FASB issued an accounting standard requiring share-based payment awards that entitle their holders to receive nonforfeitable dividends or dividend equivalents before vesting should be considered participating securities and need to be included in the earnings allocation in computing earnings per share (EPS) under the two-class method. The two-class method is an earnings allocation formula that determines EPS for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. The Company s unvested restricted stock awards are considered participating securities because they entitle holders to receive nonforfeitable dividends during the vesting term. In applying the two-class method, undistributed earnings are allocated between common shares and unvested restricted stock awards. The standard was effective for the Company for the fiscal year beginning January 1, 2009 where the two-class method of computing basic and diluted EPS was applied for all periods presented. See Note 7 for additional information.

In May 2008, the FASB issued an accounting standard which clarifies that convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are not within the scope of the Debt topic of the FASB ASC. Instead, issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the issuer s nonconvertible debt borrowing rate when recognizing interest cost in subsequent periods. The standard was effective for the Company s Convertible Junior Subordinated Debentures for the fiscal year beginning January 1, 2009. Prior period balances in this report have been adjusted to conform with these provisions. See Note 12 for additional information.

In March 2008, the FASB issued an accounting standard which expands the disclosure requirements for derivative instruments and hedging activities. The standard specifically requires entities to provide enhanced disclosures addressing the following: (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under the Derivatives and Hedging topic of the FASB ASC, and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The standard was effective for the Company for the fiscal year beginning January 1, 2009. While the standard had an impact on the Company s disclosures, it did not affect the Company s results of operations or financial condition. These additional disclosures are included in Note 3.

In December 2007, the FASB issued an accounting standard which establishes accounting and reporting guidance for noncontrolling interests in partially-owned consolidated subsidiaries and the loss of control of subsidiaries. The standard requires noncontrolling interests (minority interests) to be reported as a separate component of equity. In addition, the standard requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. The standard was effective for the Company for the fiscal year beginning January 1, 2009. Prior period balances in this report have been adjusted to conform with these provisions.

In December 2007, the FASB issued an accounting standard which changes the principles and requirements for the recognition and measurement of identifiable assets acquired, liabilities assumed and any

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

noncontrolling interest of an acquiree in the financial statements of an acquirer. This standard also provides for the recognition and measurement of goodwill acquired in a business combination and related disclosure. This standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning January 1, 2009. In April 2009, the FASB issued additional guidance on this topic, which amended and clarified the initial recognition and measurement, subsequent measurement and accounting and related disclosures arising from contingencies in a business combination. Under this guidance, assets acquired and liabilities assumed in a business combination that arise from contingencies should be recognized at fair value on the acquisition date if fair value can be determined during the measurement period. If fair value cannot be determined, companies should typically account for the acquired contingencies using existing guidance. This standard is effective for business combinations with an acquisition date that is on or after the beginning of the first annual reporting period beginning January 1, 2009.

In September 2006, the FASB issued an accounting standard which establishes a framework for measuring fair value under U.S. generally accepted accounting principles (GAAP) and expands disclosures about fair value measurements. The standard applies under accounting pronouncements that require or permit fair value measurements, but the standard does not require any new fair value measurements. In February 2008, the FASB amended the standard to exclude leasing transactions and to delay the effective date by one year for nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The Company adopted the standard on a prospective basis on January 1, 2008. In October 2008, the FASB issued additional guidance, which clarifies the application of the standard in an inactive market and demonstrated how the fair value of a financial asset is determined when the market for that financial asset is inactive. This guidance was effective upon issuance, including prior periods for which financial statements had not been issued. The adoption of the standard did not have a material impact on the Company s determination of fair value for financial assets. See Note 3 for additional details on fair value.

Accounting Standards Not Yet Implemented

In June 2009, the FASB issued accounting guidance which modifies how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The guidance clarifies that the determination of whether a company is required to consolidate an entity is based on, among other things, an entity s purpose and design and a company s ability to direct the activities of the entity that most significantly impact the entity s economic performance. The guidance also requires an ongoing reassessment of whether a company is the primary beneficiary of a variable interest entity, and additional disclosures about a company s involvement in variable interest entities and any associated changes in risk exposure. The guidance is applicable for annual periods beginning after November 15, 2009 (January 1, 2010 for the Company), at which time the Company will begin the monitoring and assessment of its business ventures in accordance with the guidance.

In June 2009, the FASB issued an accounting standard that seeks to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance and cash flows; and a transferor s continuing involvement, if any, in transferred financial assets. The standard is effective for annual periods beginning after November 15, 2009 (January 1, 2010 for the Company). While the adoption of this guidance will have an impact on the Company s disclosures, it will not affect the Company s results of operations, financial condition or cash flows.

Sales

The Company s revenue from coal sales is realized and earned when risk of loss passes to the customer. Under the typical terms of the Company s coal supply agreements, title and risk of loss transfer to the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

customer at the mine or port, where coal is loaded to the transportation source(s) that serves each of the Company s mines. The Company incurs certain add-on taxes and fees on coal sales. Reported coal sales include taxes and fees charged by various federal and state governmental bodies and the freight charges on destination customer contracts.

Other Revenues

Other revenues include royalties related to coal lease agreements, sales agency commissions, farm income, property and facility rentals, generation development activities, net revenues from coal trading activities accounted for under the Derivatives and Hedging guidance of the ASC and contract termination or restructuring payments. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced.

Discontinued Operations and Assets Held for Sale

The Company classifies items within discontinued operations in the consolidated statements of operations when the operations and cash flows of a particular component (defined as operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity) of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal transaction, and the Company will no longer have any significant continuing involvement in the operations of that component. See Note 2 for additional details related to discontinued operations and assets held for sale.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with original maturities of three months or less.

Inventories

Materials and supplies and coal inventory are valued at the lower of average cost or market. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs.

Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Capitalized interest in 2009, 2008 and 2007 was immaterial.

Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Costs incurred to maintain current production capacity at a mine and exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.

Coal reserves are recorded at cost, or at fair value in the case of acquired businesses. The net book value of coal reserves totaled $5.3 billion as of December 31, 2009 and $5.4 billion as of December 31, 2008. These coal reserves include mineral rights for leased coal interests and advance royalties that had a net book value of $4.0 billion as of December 31, 2009 and $4.1 billion as of December 31, 2008. The remaining net book

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

value of coal reserves of $1.3 billion at December 31, 2009 and 2008 relates to coal reserves held by fee ownership. Amounts attributable to properties where the Company was not currently engaged in mining operations or leasing to third parties and, therefore, the coal reserves were not currently being depleted was $1.9 billion as of December 31, 2009 and 2008.

Depletion of coal reserves and amortization of advance royalties is computed using the units-of-production method utilizing only proven and probable reserves (as adjusted for recoverability factors) in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method. Depreciation of plant and equipment (excluding life of mine assets) is computed using the straight-line method over the estimated useful lives as follows:

	Years
Building and improvements	10 to 20
Machinery and equipment	3 to 37
Leasehold improvements	Life of Lease

In addition, certain plant and equipment assets associated with mining are depreciated using the straight-line method over the estimated life of the mine, which varies from one to 37 years.

Investments in Joint Ventures

The Company accounts for its investments in less than majority owned corporate joint ventures under either the equity or cost method. The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost, and any difference between the cost of the Company s investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company s pro rata share of earnings from joint ventures and basis difference amortization is reported in the consolidated statements of operations in (Income) loss from equity affiliates. Included in the Company s equity method investments is its joint venture interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. In 2009, the Company recognized an impairment loss of $34.7 million related to its interest in Carbones del Guasare based on the joint venture s deteriorating operating results (resulting in 2009 equity losses of $19.9 million), ongoing cash flow issues resulting in no dividend payments since January 2008, the Company s expectations concerning ongoing operating and cash flow issues for the joint venture and uncertainty impacting recoverability of this investment. The table below summarizes the book value of the Company s equity method investments, which is reported in Investments and other assets in the consolidated balance sheets, the income (loss) from its equity affiliates and dividends received from its equity investments:

		Income (loss) from equity affiliates for the year ended
	Book value at December 31,	**December 31,**

	2009	2008	2009	2008	2007
			(Dollars in millions)		
Interest in Carbones del Guasare	$	$ 54.2	$ (54.6)	$ 5.7	$ 21.2
Other equity method investments	14.1	7.0	(14.5)	(5.7)	(6.7)
Total equity method investments	$ 14.1	$ 61.2	$ (69.1)	$	$ 14.5

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PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Retirement Obligations

The Company s asset retirement obligation (ARO) liabilities primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with applicable reclamation laws in the U.S. and Australia as defined by each mining permit.

The Company estimates its ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third-party to perform the required work. Spending estimates are escalated for inflation and then discounted at the credit-adjusted, risk-free rate. The Company records an ARO asset associated with the discounted liability for final reclamation and mine closure. The obligation and corresponding asset are recognized in the period in which the liability is incurred. The ARO asset is amortized on the units-of-production method over its expected life and the ARO liability is accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate historical credit-adjusted, risk-free rate. The Company also recognizes an obligation for contemporaneous reclamation liabilities incurred as a result of surface mining. Contemporaneous reclamation consists primarily of grading, topsoil replacement and re-vegetation of backfilled pit areas.

Environmental Liabilities

Included in Other noncurrent liabilities are accruals for other environmental matters that are recorded in operating expenses when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Accrued liabilities are exclusive of claims against third parties and are not discounted. In general, costs related to environmental remediation are charged to expense.

Income Taxes

Income taxes are accounted for using a balance sheet approach. The Company accounts for deferred income taxes by applying statutory tax rates in effect at the reporting date of the balance sheet to differences between the book and tax basis of assets and liabilities. A valuation allowance is established if it is more likely than not that the related tax benefits will not be realized. In determining the appropriate valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and the overall deferred tax position.

The Company recognized the tax benefit from uncertain tax positions only if it is more likely than not the tax position will be sustained on examination by the taxing authorities. The tax benefits recognized from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. To the extent the Company s assessment of such tax positions changes, the change in estimate will be recorded in the period in which the determination is made. Tax-related interest and penalties are classified as a component of income tax expense.

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions by accruing the costs of benefits to be provided over the employees period of active service. These costs are determined on an actuarial basis. The Company s consolidated balance sheets reflect the funded status of postretirement benefits.

Pension Plans

The Company sponsors non-contributory defined benefit pension plans accounted for by accruing the cost to provide the benefits over the employees period of active service. These costs are determined on an

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

actuarial basis. The Company s consolidated balance sheets reflect the funded status of the defined benefit pension plans.

Derivatives

The Company recognizes at fair value all derivatives as assets or liabilities on the consolidated balance sheets. Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in the consolidated statements of operations, along with the offsetting gain or loss related to the underlying hedged item.

Non-derivative contracts and derivative contracts for which the Company has elected to apply the normal purchase/normal sale exception are accounted for on an accrual basis.

Gains or losses on derivative financial instruments designated as cash flow hedges are recorded as a separate component of stockholders equity until the hedged transaction occurs (or until hedge ineffectiveness is determined), at which time gains or losses are reclassified to the consolidated statements of operations in conjunction with the recognition of the underlying hedged item. To the extent that the periodic changes in the fair value of the derivatives exceed the changes in the hedged item, the ineffective portion of the periodic non-cash changes are recorded in the consolidated statements of operations in the period of the change. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes the mark-to-market movements in the consolidated statements of operations in the period of the change. The potential for hedge ineffectiveness is present in the design of the Company s cash flow hedge relationships and is discussed in detail in Note 3.

Use of Estimates in the Preparation of the Consolidated Financial Statements

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

Impairment of Long-Lived Assets

The Company records impairment losses on long-lived assets used in operations when events and circumstances indicate that assets might be impaired and the undiscounted cash flows estimated to be generated by those assets under various assumptions are less than the carrying amounts of the assets. Impairment losses are measured by comparing the estimated fair value of the impaired asset to its carrying amount. There were no impairment losses recorded during the years ended December 31, 2009, 2008 or 2007.

Fair Value

For assets and liabilities that are recognized or disclosed at fair value in the consolidated financial statements, the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Company s asset and liability derivative positions are offset on a counterparty-by-counterparty basis if the contractual agreement provides for the net settlement of contracts with the counterparty in the event of default or termination of any one contract.

Foreign Currency

The Company s foreign subsidiaries utilize the U.S. dollar as their functional currency. As such, monetary assets and liabilities are remeasured at year-end exchange rates while non-monetary items are remeasured at

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

historical rates. Income and expense accounts are remeasured at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement related to tax balances are included as a component of income tax expense while all other remeasurement gains and losses are included in operating costs and expenses. The foreign currency remeasurement loss for the year ended December 31, 2009, was $55.4 million. The foreign currency remeasurement gain for the year ended December 31, 2008 was $71.1 million and the foreign currency remeasurement loss for the year ended December 31, 2007 was $61.2 million.

Share-Based Compensation

The Company accounts for share-based compensation at the grant date fair value of awards and recognizes the related expense over the vesting period of the award.

Exploration and Drilling Costs

Exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves.

Advance Stripping Costs

Pre-production: At existing surface operations, additional pits may be added to increase production capacity in order to meet customer requirements. These expansions may require significant capital to purchase additional equipment, expand the workforce, build or improve existing haul roads and create the initial pre-production box cut to remove overburden (i.e., advance stripping costs) for new pits at existing operations. If these pits operate in a separate and distinct area of the mine, the costs associated with initially uncovering coal (i.e., advance stripping costs incurred for the initial box cuts) for production are capitalized and amortized over the life of the developed pit consistent with coal industry practices.

Post-production: Advance stripping costs related to post-production are expensed as incurred. Where new pits are routinely developed as part of a contiguous mining sequence, the Company expenses such costs as incurred. The development of a contiguous pit typically reflects the planned progression of an existing pit, thus maintaining production levels from the same mining area utilizing the same employee group and equipment.

Reclassifications

Certain amounts in prior periods have been reclassified to conform with the current year presentation, with no effect on previously reported net income or stockholders equity.

(2) Discontinued Operations

Patriot Coal Corporation

On October 31, 2007, the Company spun-off portions of its formerly Eastern U.S. Mining operations business segment through a dividend of all outstanding shares of Patriot Coal Corporation (Patriot), which is now an independent public company traded on the New York Stock Exchange (symbol PCX). The spin-off included eight company-operated mines, two joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves.

Revenues from the spun-off operations are the result of supply agreements the Company entered into with Patriot to meet commitments under non-assignable pre-existing customer agreements sourced from Patriot mining operations. The Company makes no profit as part of these arrangements. The loss from discontinued operations for the year ended December 31, 2008 was primarily related to the write-off of a $19.4 million

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

receivable related to excise taxes previously paid on export shipments produced from discontinued operations. As part of the Patriot spin-off, the Company retained a receivable for excise tax refunds on export shipments that had previously been ruled unconstitutional by the appellate court. The U.S. Supreme Court reversed the appellate court s ruling on April 15, 2008, and the Company recorded the charge to discontinued operations.

In October 2008, the Energy Improvement and Extension Act of 2008 was enacted, which contained provisions that allow for the refund of coal excise tax collected on coal exported from the U.S. between January 1, 1990 and the date of the legislation. The Company s claim for refund was approved by the Internal Revenue Service (IRS) in 2009. During the year ended December 31, 2009 the refund of approximately $35 million (net of income taxes) was recorded in Income (loss) from discontinued operations, net of income taxes in the consolidated statement of operations. Approximately $59 million was received during 2009 and is shown in Net cash used in discontinued operations as a component of cash flows from operating activities in the consolidated statements of cash flows.

Baralaba

In December 2008, the Company sold its Baralaba Mine, a non-strategic Australian mine, for $25.8 million of cash proceeds and an Australian dollar note receivable valued at approximately $8.7 million on December 31, 2008, resulting in a gain of $26.2 million. In 2008, the non-cash portion of this transaction was excluded from the investing section of the consolidated statement of cash flows.

Chain Valley

In December 2009, the Company sold its Chain Valley Mine, a non-strategic Australian mine, and recorded a loss of $10.0 million in conjunction with the sale.

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PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summary Financial Information

Operating results related to discontinued operations and assets held for sale were as follows:

	Year Ended December 31, 2009	2008	2007
	(Dollars in millions)		
Revenues:			
Patriot	$ 275.7	$ 431.2	$ 1,024.5
Baralaba		18.8	22.1
Chain Valley	20.6	32.4	21.3
Assets held for sale	5.2	30.6	39.5
Total	$ 301.5	$ 513.0	$ 1,107.4
Income (loss) before income taxes:			
Patriot	$ 35.4	$ (23.0)	$ (238.4)
Baralaba		10.5	(10.6)
Chain Valley	(16.8)	(3.5)	(6.9)
Assets held for sale	(4.2)	(44.6)	13.5)
Total	$ 14.4	$ (60.6)	$ (269.4)
Income tax provision (benefit):			
Patriot	$ 13.6	$ (8.9)	$ (81.5)
Baralaba[(1)]			
Chain Valley	(2.8)	(6.0)	(2.5)
Assets held for sale	(1.5)	(16.9)	(5.3)
Total	$ 9.3	$ (31.8)	$ (89.3)
Income (loss), net of income taxes:			
Patriot	$ 21.8	$ (14.1)	$ (156.9)
Baralaba		10.5	(10.6)
Chain Valley	(14.0)	2.5	(4.4)
Assets held for sale	(2.7)	(27.7)	(8.2)
Total	$ 5.1	$ (28.8)	$ (180.1)

(1)

Income tax benefits associated with Baralaba s operating results were completely offset by valuation allowances recorded against the deferred tax assets created by the operating losses.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Assets and liabilities related to discontinued operations were as follows:

	December 31, 2009			December 31, 2008			
	Patriot[1]	Assets held for sale	Total	Patriot[1]	Chain Valley	Assets held for sale	Total
	(Dollars in millions)						
Assets							
Current assets							
Other current assets	$ 29.2	$	$ 29.2	$ 51.0	$ 3.1	$	$ 54.1
Total current assets	29.2		29.2	51.0	3.1		54.1
Noncurrent assets							
Investments and other assets		11.4	11.4	4.9	17.8	12.6	35.3
Total assets	$ 29.2	$ 11.4	$ 40.6	$ 55.9	$ 20.9	$ 12.6	$ 89.4
Liabilities							
Current liabilities							
Accounts payable and accrued expenses	$ 40.6	$	$ 40.6	$ 69.1	$ 5.4	$	$ 74.5
Total current liabilities	40.6		40.6	69.1	5.4		74.5
Noncurrent liabilities							
Other noncurrent liabilities		6.5	6.5	12.8	4.6	9.4	26.8
Total liabilities	$ 40.6	$ 6.5	$ 47.1	$ 81.9	$ 10.0	$ 9.4	$ 101.3

(1) Other current assets included receivables from customers in relation to the supply agreements with Patriot and Accounts payable and accrued expenses included the amounts due to Patriot on these pass-through transactions.

(3) Labor Relations, Risk Management and Fair Value Measurements

Employees

As of December 31, 2009, the Company had approximately 7,300 employees, which included approximately 5,400 hourly employees. As of December 31, 2009, approximately 29% of the Company s hourly employees were represented by organized labor unions and generated 10% of its 2009 coal production. Relations with its employees and, where applicable, organized labor are important to the Company s success.

U.S. Labor Relations. Hourly workers at the Company s Kayenta Mine in Arizona are represented by the United Mine Workers of America (UMWA) under the Western Surface Agreement, which is effective through September 2, 2013. This agreement covers approximately 7% of the Company s U.S. subsidiaries hourly employees, who generated 4% of the Company s U.S. production during the year ended December 31, 2009.

Hourly workers at the Company s Willow Lake Mine in Illinois are represented by the International Brotherhood of Boilermakers under a labor agreement that expires April 15, 2011. This agreement covers approximately 9% of the Company s U.S. subsidiaries hourly employees, who generated approximately 2% of the Company s U.S. production during the year ended December 31, 2009.

Australian Labor Relations. The Australian coal mining industry is unionized and the majority of workers employed at the Company s Australian Mining operations are members of trade unions. The

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Construction Forestry Mining and Energy Union represents the Company s 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. The current labor agreement at the Company s Metropolitan Mine expires in June 2010; renegotiations for a new agreement will commence in the first quarter of 2010. The labor agreement for the Wambo Mine coal handling plant was renewed in 2008 and expires in 2011. The labor agreement for the Wambo Underground Mine was renewed in early 2009 and will expire in 2012. For the Wilkie Creek Mine (expired October 2009) and the North Goonyella Mine (expired May 2009), the Company has reached agreements in principle, with the vote of the unions and employees expected to take place in late February 2010.

Risk Management Non Coal Trading

The Company is exposed to various types of risk in the normal course of business, including fluctuations in commodity prices, interest rates and foreign currency exchange rates. These risks are actively monitored in an effort to ensure compliance with the risk management policies of the Company. In most cases, commodity price risk (excluding coal trading activities) related to the sale of coal is mitigated through the use of long-term, fixed-price contracts rather than financial instruments.

Interest Rate Swaps. The Company is exposed to interest rate risk on its fixed rate and variable rate long-term debt. The interest rate risk associated with the fair value of the Company s fixed rate borrowings is managed using fixed-to-floating interest rate swaps to effectively convert a portion of the underlying cash flows on the debt into variable rate cash flows. The Company designates these swaps as fair value hedges, with the objective of hedging against changes in the fair value of the fixed rate debt that results from market interest rate changes. The interest rate risk associated with the Company s variable rate borrowings is managed using floating-to-fixed interest rate swaps. The Company designates these swaps as cash flow hedges, with the objective of reducing the variability of cash flows associated with market interest rate changes.

Foreign Currency Risk. The Company is exposed to foreign currency exchange rate risk on Australian dollar expenditures made in its Australian Mining segment. This risk is managed by entering into forward contracts and options that the Company designates as cash flow hedges, with the objective of reducing the variability of cash flows associated with forecasted Australian dollar expenditures.

Diesel Fuel and Explosives Hedges. The Company is exposed to commodity price risk associated with diesel fuel in the U.S. and Australia and explosives in the U.S. Explosives costs and a portion of the diesel fuel costs in Australia are included in the fees paid to the Company s contract miners. This risk is managed through the use of fixed price contracts, cost plus contracts and derivatives, primarily swaps. The Company has generally designated the swap contracts as cash flow hedges, with the objective of reducing the variability of cash flows associated with the forecasted purchase of diesel fuel and explosives.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Notional Amounts and Fair Value. The following summarizes the Company s interest rate, foreign currency and commodity positions at December 31, 2009:

	Notional Amount by Year of Maturity						
	Total	2010	2011	2012	2013	2014	2015 and thereafter
Interest Rate Swaps							
Fixed-to-floating (dollars in millions)	$ 50.0	$	$	$	$ 50.0	$	$
Floating-to-fixed (dollars in millions)	$ 120.0	$	$ 120.0	$	$	$	$
Foreign Currency							
A$:US$ hedge contracts (A$ millions)	$ 3,291.7	$ 1,299.3	$ 994.8	$ 742.6	$ 120.0	$ 135.0	$
Commodity Contracts							
Diesel fuel hedge contracts (million gallons)	177.8	71.1	65.3	41.4			
U.S. explosives hedge contracts (million MMBtu)	3.0	3.0					

	Account Classification by			
	Cash flow hedge	Fair value hedge	Economic hedge	Fair Value Asset (Liability) (Dollars in millions)
Interest Rate Swaps				
Fixed-to-floating (dollars in millions)	$	$ 50.0	$	$ 1.5
Floating-to-fixed (dollars in millions)	$ 120.0	$	$	$ (9.8)
Foreign Currency				
A$:US$ hedge contracts (A$ millions)	$ 3,291.7	$	$	$ 206.1
Commodity Contracts				
Diesel fuel hedge contracts (million gallons)	177.8			$ (22.2)
U.S. explosives hedge contracts (million MMBtu)	3.0			$ (4.8)

Hedge Ineffectiveness. The Company assesses both at inception and at least quarterly thereafter, whether the derivatives used in hedging activities are highly effective at offsetting the changes in the anticipated cash flows of the hedged item. The effective portion of the change in the fair value is recorded as a separate component of stockholders equity until the hedged transaction impacts reported earnings, at which time gains and losses are reclassified to the consolidated statements of operations at the time of the recognition of the underlying hedged item. The ineffective portion of the derivative s change in fair value is recorded in the consolidated statements of operations. In addition, if the hedging relationship ceases to be highly effective, or it becomes probable that a forecasted transaction is no longer expected to occur, gains and losses on the derivative are recorded to the consolidated statements of operations.

A measure of ineffectiveness is inherent in hedging future diesel fuel purchases with derivative positions based on crude oil and refined petroleum products.

The Company s hedging of future explosives purchases also has an inherent measure of ineffectiveness as the derivative positions are primarily based on natural gas, which closely matches the contractual purchase

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

price of explosives since price changes occur in a constant ratio of MMBtu per ton in the manufacture of explosives and generally carry a fixed surcharge.

With respect to the interest rate swaps, there was no hedge ineffectiveness recognized in the consolidated statements of operations for these instruments during the years ended December 31, 2009, 2008, or 2007.

The table below shows the classification and amounts of pre-tax gains and losses related to the Company s non-trading hedges during the year ended December 31, 2009:

Financial Instrument	Income Statement Classification Gains (Losses) - Realized	Gain (loss) recognized in income on non designated derivatives[(1)]	Gain (loss) recognized in other comprehensive income on derivative (effective portion)	Gain (loss) reclassified from other comprehensive income into income (effective portion)	Gain (loss) reclassified from other comprehensive income into income (ineffective portion)
			(Dollars in millions)		
Interest rate swaps:					
- Cash flow hedges	Interest expense	$	$ 0.2	$ (5.5)	$
Diesel fuel hedge contracts:					
- Cash flow hedges	Operating costs and expenses		67.9	(84.4)	0.7
- Economic hedges	Operating costs and expenses	(0.6)			
Explosives cash flow hedge contracts:					
- Cash flow hedges	Operating costs and expenses		(2.4)	(13.9)	
- Economic hedges	Operating costs and expenses	(2.1)			
Foreign currency cash flow hedge contracts	Operating costs and expenses		458.0	(30.8)	
Total		$ (2.7)	$ 523.7	$ (134.6)	$ 0.7

(1) Amounts relate to diesel fuel and explosives hedge derivatives that were de-designated in 2009.

As of December 31, 2009, the classification and amount of derivatives presented on a gross basis are as follows:

	Fair Value			
Financial Instrument	**Other Current Assets**	**Investments and Other Assets**	**Accounts Payable and Accrued Expenses**	**Other Noncurrent Liabilities**
	(Dollars in millions)			
Interest rate swaps:				
- Fair value hedges	$	$ 1.5	$	$
- Cash flow hedges				9.8
Diesel fuel cash flow hedge contracts	142.9	243.8	167.5	241.4
Explosives cash flow hedge contracts	15.9		20.7	
Foreign currency cash flow hedge contracts	110.6	100.2	1.6	3.1
Total	$ 269.4	$ 345.5	$ 189.8	$ 254.3

The Company elected the trading exemption under GAAP for its coal trading transactions which allows for reduced disclosure since it is the Company s policy to include these instruments as a part of its trading book. For further information, see Risk Management - Coal Trading below.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Risk Management Coal Trading

The Company engages in direct and brokered trading of coal, ocean freight and fuel-related commodities in over-the-counter markets (coal trading), some of which is subsequently exchange-cleared and some of which is bilaterally-cleared. Except those for which the Company has elected to apply a normal purchases and normal sales exception, all derivative coal trading contracts are accounted for on a fair value basis. For derivative trading contracts, the Company establishes fair values using bid/ask price quotations or other market assessments obtained from multiple, independent third-party brokers to value its trading positions from the over-the-counter market. Prices from these sources are then averaged to obtain trading position values. While the Company does not anticipate any decrease in the number of third-party brokers or market liquidity, such events could erode the quality of market information and therefore in valuing its market positions should the number of third-party brokers decrease or if market liquidity is reduced. For its exchange-cleared positions, the Company utilizes exchange-published settlement prices. See Note 5 for information related to the maturity and valuation of the Company s trading portfolio.

Trading Revenue by Type of Instrument	**Year Ended December 31, 2009 (Dollars in millions)**	
Commodity swaps and options	$	176.5
Physical commodity purchase / sale contracts		85.0
Total trading revenue	$	261.5

Trading revenues are recorded in Other revenues in the consolidated statements of operations and include realized and unrealized gains and losses on derivative instruments, including those under the normal purchases and normal sales exception.

Hedge Ineffectiveness Coal Trading. In some instances, the Company has designated an existing coal trading derivative as a hedge and, thus, the derivative has a non-zero fair value at hedge inception. The off-market nature of these derivatives, which is best described as an embedded financing element within the derivative, is a source of ineffectiveness. In other instances, the Company uses a coal trading derivative that settles at a different time or has a different location basis than the occurrence of the cash flow being hedged. These collectively yield ineffectiveness to the extent that the derivative hedge contract does not exactly offset changes in the fair value or expected cash flows of the hedged item.

Nonperformance and Credit Risk

The fair value of the Company s assets and liabilities reflect adjustments for nonperformance and credit risk. The concentration of nonperformance and credit risk is substantially with electric utilities, steel producers, energy producers and energy marketers. The Company s policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to regularly monitor the credit extended. If the Company engages in a transaction with a counterparty that does not meet its credit standards, the Company seeks to protect its position by requiring the counterparty to provide an appropriate credit enhancement. Also, when appropriate (as determined by its credit management function), the Company has taken steps to reduce its exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for the Company s benefit to serve as collateral in the event of a failure to pay or perform. To reduce its credit exposure related to trading and brokerage activities, the Company seeks to enter into netting agreements with counterparties that permit the Company to offset receivables and payables with such counterparties and, to the extent required, will post or receive margin amounts associated with exchange-cleared positions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company conducts its various hedging activities related to foreign currency, interest rate, and fuel and explosives exposures with a variety of highly-rated commercial banks. In light of the recent turmoil in the financial markets the Company continues to closely monitor counterparty creditworthiness.

Certain of the Company s derivative instruments require the parties to provide additional performance assurances whenever a material adverse event jeopardizes one party s ability to perform under the instrument. In the event the Company were to sustain a material adverse event (using commercially reasonable standards), the counterparties could request collateralization on derivative instruments in net liability positions, which based on an aggregate fair value on December 31, 2009, could require the Company to post up to $83.8 million of collateral to its counterparties.

Certain of the Company s other derivative instruments require the parties to provide additional performance assurances whenever a credit downgrade occurs below a certain level as specified in each underlying contract. The terms of such instruments typically require additional collateralization on an incremental basis, which is commensurate with the severity of the credit downgrade. As of December 31, 2009, if a credit downgrade were to occur below a certain level, the Company s additional collateral requirements are estimated to be approximately $15.9 million (for which the Company currently has posted approximately $0.8 million) to its counterparties based on the aggregate fair value of all derivative instruments with such features that are in a net liability position.

The Company is required to post collateral on its exchange-settled positions for its entire net liability position, which was $18.1 million as of December 31, 2009. In addition, as of December 31, 2009, the Company has posted $29.7 million of collateral to meet the requirements of the respective exchanges (reflected in Other current assets).

Fair Value Measurements

The Company uses a three-level fair value hierarchy that categorizes assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. These levels include: Level 1, inputs are quoted prices in active markets for the identical assets or liabilities; Level 2, inputs other than quoted prices included in Level 1 that are directly or indirectly observable through market-corroborated inputs; and Level 3, inputs are unobservable, or observable but cannot be market-corroborated, requiring the Company to make assumptions about pricing by market participants.

The following tables set forth the hierarchy of the Company s net financial asset (liability) positions for which fair value is measured on a recurring basis:

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Commodity swaps and options coal trading activities	$ (1.7)	$ 80.7	$	$ 79.0
Commodity swaps and options other than coal		(27.0)		(27.0)
Physical commodity purchase/sale contracts coal trading activities		70.2	17.0	87.2
Interest rate swaps		(8.3)		(8.3)

Foreign currency hedge contracts		206.1		206.1
Total net financial assets (liabilities)	$ (1.7)	$ 321.7	$ 17.0	$ 337.0

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Commodity swaps and options coal trading activities	$ (17.0)	$ 233.7	$ (1.1)	$ 215.6
Commodity swaps and options other than coal		(194.7)		(194.7)
Physical commodity purchase/sale contracts coal trading activities		104.1	38.9	143.0
Interest rate swaps		(9.3)		(9.3)
Foreign currency hedge contracts		(283.8)		(283.8)
Total net financial assets (liabilities)	$ (17.0)	$ (150.0)	$ 37.8	$ (129.2)

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including LIBOR yield curves, New York Mercantile Exchange and Intercontinental Exchange indices (ICE), broker quotes, published indices, and other market quotes. Below is a summary of the Company s valuation techniques for Level 1 and 2 financial assets and liabilities:

Commodity swaps and options coal trading activities: generally valued based on unadjusted quoted prices in active markets (Level 1) or a valuation that is corroborated by the use of market-based pricing (Level 2).

Commodity swaps and options other than coal: generally valued based on a valuation that is corroborated by the use of market-based pricing (Level 2).

Physical commodity purchase/sale contracts coal trading activities: purchases and sales at locations with significant market activity corroborated by market-based information (Level 2).

Interest rate swaps: valued based on modeling observable market data and corroborated with statements from counterparties (Level 2).

Foreign currency hedge contracts: valued utilizing inputs obtained in quoted public markets (Level 2).

Commodity swaps and options and physical commodity purchase/sale contracts transacted in less liquid markets or contracts, such as long-term arrangements with limited price availability were classified in Level 3. These instruments or contracts are valued based on quoted inputs from brokers or counterparties, or reflect methodologies that consider historical relationships among similar commodities to derive the Company s best estimate of fair value. The Company has consistently applied these valuation techniques in all periods presented, and believes it has obtained the most accurate information available for the types of derivative contracts held.

The following table summarizes the changes in the Company s recurring Level 3 net financial assets:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(Dollars in millions)	
Beginning of period	$ 37.8	$ 128.7
Total gains or losses (realized/unrealized):		
Included in earnings	(2.9)	(9.8)
Included in other comprehensive income	(1.6)	3.4
Purchases, issuances and settlements	(20.5)	(58.8)
Net transfers in (out)	4.2	(25.7)
End of period	$ 17.0	$ 37.8

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the changes in unrealized gains (losses) relating to Level 3 net financial assets held both as of the beginning and the end of the period:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(Dollars in millions)	
Changes in unrealized gains (losses)[1]	$ 15.6	$ (34.8)

[1] Within the consolidated statements of operations for the periods presented, unrealized gains and losses from Level 3 items are combined with unrealized gains and losses on positions classified in Level 1 or 2, as well as other positions that have been realized during the applicable periods.

Fair Value Other Financial Instruments

The following methods and assumptions were used by the Company in estimating fair values for other financial instruments as of December 31, 2009 and 2008:

Cash and cash equivalents, accounts receivable and accounts payable and accrued expenses have carrying values which approximate fair value due to the short maturity or the financial nature of these instruments.

Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available, and otherwise on estimated borrowing rates to discount the cash flows to their present value. The carrying amounts of the 7.875% Senior Notes due 2026 and the Convertible Junior Subordinated Debentures due 2066 are net of the respective unamortized note discounts.

The carrying amounts and estimated fair values of the Company s debt are summarized as follows:

	December 31, 2009		December 31, 2008	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Dollars in millions)			
Long-term debt	$ 2,752.3	$ 2,828.8	$ 2,793.6	$ 2,472.1

(4) Resource Management and Other Commercial Events

In 2008, the Company sold approximately 58 million tons of non-strategic coal reserves and surface lands located in Kentucky for $21.5 million cash proceeds and a note receivable of $54.9 million, and recognized a gain of

$54.0 million. The note receivable was paid in two installments, $30.0 million of which was received in December 2008 with the balance received in June 2009. The non-cash portion of this transaction was excluded from the investing section of the consolidated statement of cash flows until the cash was received.

In 2007, the Company sold approximately 172 million tons of coal reserves and surface lands to the Prairie State Energy Campus (Prairie State) equity partners. The Company recognized a gain totaling $26.4 million and received $114.3 million in cash proceeds associated with this transaction. See Note 19 for additional information regarding Prairie State.

In 2007, the Company exchanged oil and gas rights and assets in more than 860,000 acres in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for coal reserves in West Virginia and Kentucky and $15.0 million in cash proceeds. The Company s subsidiaries, including one subsidiary now owned by Patriot, received approximately 40 million tons of coal reserves. Based on the fair value of the coal reserves received, the Company recognized a $50.5 million gain on the exchange. The non-cash portion of this transaction was excluded from the investing section of the consolidated statement of cash flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) Assets and Liabilities from Coal Trading Activities

The fair value of assets and liabilities from coal trading activities is set forth below:

	December 31, 2009 Gross Basis	2009 Net Basis	2008 Gross Basis	2008 Net Basis
	(Dollars in millions)			
Assets from coal trading activities	$ 949.8	$ 276.8	$ 1,969.7	$ 662.8
Liabilities from coal trading activities	(779.3)	(110.6)	(1,548.5)	(304.2)
Subtotal	170.5	166.2	421.2	358.6
Net margin held	(4.3)		(62.6)	
Net value of coal trading positions	$ 166.2	$ 166.2	$ 358.6	$ 358.6

As of December 31, 2009, forward contracts made up 53% and 65% of the Company s trading assets and liabilities, respectively; financial swaps represent most of the remaining balances. The net fair value of coal trading positions designated as cash flow hedges of anticipated future sales was an asset of $93.0 million as of December 31, 2009 and an asset of $220.4 million as of December 31, 2008. The net value of trading positions, including those designated as hedges of future cash flows, represents the fair value of the trading portfolio.

As of December 31, 2009, the estimated future realization of the value of the Company s trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio Total
2010	46%
2011	51%
2012	3%
	100%

At December 31, 2009, 73% of the Company s credit exposure related to coal trading activities with investment grade counterparties and 27% with non-investment grade counterparties.

(6) Accounts Receivable Securitization

The Company has an accounts receivable securitization program (securitization program) through its wholly-owned, bankruptcy-remote subsidiary (Seller). Under the program, the Company contributes a pool of eligible trade receivables to the Seller, which then sells, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. The Company utilizes proceeds from the sale of its accounts receivable as an alternative to other forms of debt, effectively reducing its overall borrowing costs. The funding cost of the securitization program was $4.0 million, $10.8 million and $11.2 million for the years ended December 31, 2009, 2008 and 2007, respectively and is included in interest expense in the consolidated statements of operations. The Company continues to service the sold trade receivables but does not receive a servicing fee. The securitization program was renewed in May 2009, and amended in December 2009 and January 2010, and extends to May 2012, while the letter of credit commitment that supports the commercial paper facility underlying the securitization program must be renewed annually.

The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the consolidated balance sheets. The amount of interest in accounts receivable sold to the Conduit was $254.6 million as of December 31, 2009 and $275.0 million as of December 31, 2008. The $20.4 million decrease in the securitization program for the year ended December 31, 2009 is reflected in

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash flows from operating activities in the consolidated statements of cash flows. There was no change in the facility usage during the year ended December 31, 2008.

The Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Eligible receivables, as defined in the securitization agreement, consist of trade receivables from most of the Company s U.S. subsidiaries, and are reduced for certain items such as past due balances and concentration limits. Of the eligible pool of receivables contributed to the Seller, only a portion of the pool is sold to the Conduit. The Company continues to own $9.4 million of receivables as of December 31, 2009, which represents collateral supporting the securitization program. The Seller s interest in these receivables is subordinate to the Conduit s interest in the event of default under the securitization agreement. If the Company defaulted under the securitization agreement or if its pool of eligible trade receivables decreased significantly, the Company could be prohibited from selling any additional receivables in the future under the securitization agreement.

On January 25, 2010, the receivables purchase agreement for the accounts receivable securitization program was amended and restated to add a second multi-seller asset-backed commercial paper conduit as a purchaser.

(7) Earnings per Share

As discussed in Note 1, the Company uses the two-class method to compute basic and diluted EPS for all periods presented. The following illustrates the earnings allocation method utilized in the calculation of basic and diluted EPS.

	Year Ended December 31, 2009		
	2009	2008	2007
	(In millions, except per share amounts)		
Basic earnings per share:			
Income from continuing operations, net of income taxes	$ 457.9	$ 987.9	$ 441.6
Less: Net income (loss) attributable to noncontrolling interests	14.8	6.2	(2.3)
Income from continuing operations attributable to common stockholders before allocation of earnings to participating securities	443.1	981.7	443.9
Less: Earnings allocated to participating securities	(2.9)	(5.5)	(1.2)
Income from continuing operations attributable to common stockholders	440.2	976.2	442.7
Income (loss) from discontinued operations, net of income taxes	5.1	(28.8)	(180.1)
Net income attributable to common stockholders	$ 445.3	$ 947.4	$ 262.6
Diluted earnings per share:			
Income from continuing operations attributable to common stockholders before allocation of earnings to participating securities	$ 443.1	$ 981.7	$ 443.9
Less: Earnings allocated to participating securities	(2.9)	(5.5)	(1.2)

Income from continuing operations attributable to common stockholders before the reallocation of the earnings of participating securities	440.2	976.2	442.7
Reallocation of the earnings of participating securities			
Income from continuing operations attributable to common stockholders	440.2	976.2	442.7
Income (loss) from discontinued operations, net of income taxes	5.1	(28.8)	(180.1)
Net income attributable to common stockholders	$ 445.3	$ 947.4	$ 262.6
Weighted average shares outstanding basic	265.5	268.9	264.1
Dilutive impact of share-based compensation[1]	2.0	1.8	4.5
Weighted average shares outstanding diluted[2]	267.5	270.7	268.6

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2009		
	2009	2008	2007
	(In millions, except per share amounts)		
Basic earnings per share attributable to common stockholders:			
Income from continuing operations	$ 1.66	$ 3.63	$ 1.67
Income (loss) from discontinued operations	0.02	(0.11)	(0.68)
Net income	$ 1.68	$ 3.52	$ 0.99
Diluted earnings per share attributable to common stockholders:			
Income from continuing operations	$ 1.64	$ 3.60	$ 1.64
Income (loss) from discontinued operations	0.02	(0.10)	(0.67)
Net income	$ 1.66	$ 3.50	$ 0.97

(1) Includes the dilutive impact of stock options, restricted stock awards, deferred stock units, employee stock purchase plan and performance units.

(2) Weighted average shares outstanding excludes anti-dilutive shares totaling 0.2 million, 0.1 million and 0.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(8) Inventories

Inventories consisted of the following:

	December 31,	
	2009	2008
	(Dollars in millions)	
Materials and supplies	$ 106.5	$ 109.6
Raw coal	80.5	22.7
Saleable coal	138.1	143.9
Total	$ 325.1	$ 276.2

(9) Leases

The Company leases equipment and facilities under various noncancelable lease agreements. Certain lease agreements require the maintenance of specified ratios and contain restrictive covenants which limit indebtedness, subsidiary dividends, investments, asset sales and other Company actions. Rental expense under operating leases was $127.8 million, $121.3 million and $104.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. The gross value of property, plant, equipment and mine development assets under capital leases was $98.4 million and $108.6 million as of December 31, 2009 and 2008, respectively, related primarily to the leasing of mining equipment. The accumulated depreciation for these items was $31.0 million and $27.6 million at December 31, 2009 and 2008, respectively.

The Company also leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $439.4 million, $506.4 million and $338.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from the owner. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Wyoming and Colorado under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

development and mining of the reserves until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production or by including the lease as a part of a logical mining unit with other leases upon which development has occurred. Annual production on these federal leases must total at least 1.0% of the original amount of coal in the entire logical mining unit. In addition, royalties are payable monthly at a rate of 12.5% of the gross realization from the sale of the coal mined using surface mining methods and at a rate of 8.0% of the gross realization for coal produced using underground mining methods. The Company also leases coal reserves in Arizona from The Navajo Nation and the Hopi Tribe under leases that are administered by the U.S. Department of the Interior. These leases expire upon exhaustion of the leased reserves or upon the permanent ceasing of all mining activities on the related reserves as a whole. The royalty rates are also generally based upon a percentage of the gross realization from the sale of coal. These rates are subject to redetermination every ten years under the terms of the leases. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

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 sale prices. 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.

Future minimum lease and royalty payments as of December 31, 2009 are as follows:

Year Ended December 31,	Capital Leases	Operating Leases	Coal Lease and Royalty Obligations
		(Dollars in millions)	
2010	$ 15.1	$ 96.4	$ 11.3
2011	15.1	87.4	9.0
2012	15.1	66.2	7.8
2013	23.0	56.6	8.3
2014	12.0	43.7	6.7
2015 and thereafter		117.8	36.8
Total minimum lease payments	$ 80.3	$ 468.1	$ 79.9
Less interest	12.8		

Present value of minimum capital lease payments	$ 67.5

As of December 31, 2009, certain of the Company s lease obligations were secured by outstanding surety bonds totaling $116.3 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Trade accounts payable	$ 387.6	$ 427.2
Accrued taxes other than income	172.3	170.7
Other accrued expenses	160.0	127.0
Accrued payroll and related benefits	135.0	120.1
Income taxes payable	80.7	142.7
Accrued health care	78.7	82.5
Accrued royalties	51.1	77.7
Accrued interest	31.7	31.1
Commodity and foreign currency hedge contracts	29.4	261.1
Workers compensation obligations	8.7	8.7
Accrued environmental	7.9	7.6
Other accrued benefits	4.0	4.1
Liabilities associated with discontinued operations	40.6	69.1
Current liabilities associated with assets held for sale		5.4
Total accounts payable and accrued expenses	$ 1,187.7	$ 1,535.0

(11) Income Taxes

Income from continuing operations before income taxes consisted of the following:

	Year Ended December 31, 2009	2008	2007
	(Dollars in millions)		
U.S.	$ 281.4	$ 185.2	$ 296.1
Non U.S.	370.3	994.1	74.8
Total	$ 651.7	$ 1,179.3	$ 370.9

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PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Total income tax provision (benefit) consisted of the following:

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Current:			
U.S. federal	$ (0.7)	$	$
Non U.S.	61.7	224.7	28.9
State	1.7		0.2
Total current	62.7	224.7	29.1
Deferred:			
U.S. federal	56.0	47.1	(139.3)
Non U.S.	74.4	(81.7)	46.7
State	0.7	1.3	(7.2)
Total deferred	131.1	(33.3)	(99.8)
Total provision (benefit)	$ 193.8	$ 191.4	$ (70.7)

The income tax rate differed from the U.S. federal statutory rate as follows:

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Federal statutory rate	$ 228.1	$ 412.7	$ 129.8
Excess depletion	(44.0)	(40.1)	(55.3)
Foreign earnings rate differential	(83.6)	(119.7)	(13.5)
Remeasurement of foreign deferred taxes	74.4	(65.2)	56.0
State income taxes, net of U.S. federal tax benefit	3.4	(1.6)	0.3
Tax credits	(12.2)	(12.6)	(24.3)
Changes in valuation allowance	17.3	(44.2)	(175.7)
Changes in tax reserves	5.9	34.4	4.1
Other, net	4.5	27.7	7.9
Total provision (benefit)	$ 193.8	$ 191.4	$ (70.7)

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PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities consisted of the following:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Deferred tax assets:		
Tax credits and loss carryforwards	$ 557.1	$ 785.9
Postretirement benefit obligations	474.7	403.9
Intangible tax asset and purchased contract rights	30.9	58.1
Accrued reclamation and mine closing liabilities	57.0	46.1
Accrued long-term workers compensation liabilities	23.1	12.6
Employee benefits	80.3	56.2
Financial guarantee	20.1	23.9
Others	39.5	56.5
Total gross deferred tax assets	1,282.7	1,443.2
Deferred tax liabilities:		
Property, plant, equipment and mine development, leased coal interests and advance royalties, principally due to differences in depreciation, depletion and asset writedowns	1,221.0	1,154.2
Unamortized discount on Convertible Junior Subordinated Debentures	139.6	139.9
Hedge activities	29.2	35.3
Investments and other assets	64.8	75.9
Total gross deferred tax liabilities	1,454.6	1,405.3
Valuation allowance	(87.2)	(57.0)
Net deferred tax liability	$ (259.1)	$ (19.1)
Deferred taxes are classified as follows:		
Current deferred income taxes	$ 40.0	$ 1.7
Noncurrent deferred income taxes	(299.1)	(20.8)
Net deferred tax liability	$ (259.1)	$ (19.1)

The Company s tax credits and loss carryforwards included alternative minimum tax (AMT) and general business credits of $73.3 million and $62.4 million, U.S. net operating loss (NOL) carryforwards of $392.1 million and $653.5 million and foreign loss carryforwards of $91.7 million and $70.0 million as of December 31, 2009 and 2008, respectively. The AMT credits and foreign NOL and capital loss carryforwards have no expiration date and the

U.S. NOL carryforwards begin to expire in the year 2025. The Company evaluated and assessed the expected near-term utilization of NOLs, future book and taxable income, available tax strategies and the overall deferred tax position to determine the appropriate amount and timing of valuation allowance adjustments. Of the $17.3 million change in the valuation allowance, the largest component of the 2009 assessment was a $15.7 million increase of a valuation allowance on AMT credits. Significant reductions of valuation allowance were made to foreign NOLs during the 2008 assessment and on U.S. NOL carryforwards during the 2007 assessments. The remaining valuation allowance at December 31, 2009 of $87.2 million represents a reserve for AMT credits and certain foreign deferred tax assets.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The total amount of the net unrecognized tax benefits was $109.2 million ($113.2 million gross) at December 31, 2009 and was $176.9 million ($186.3 million gross) at December 31, 2008. The amount of the Company s gross unrecognized tax benefits has decreased by $73.1 million since January 1, 2009 primarily as a result of the Company s IRS audit for the 2005 and 2006 tax years. The corresponding adjustment was a reduction of the deferred tax asset associated with net operating losses. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits is as follows (dollars in millions):

	Year Ended December 31,		
	2009	2008	2007
Balance at beginning of period	$ 186.3	$ 152.6	$ 144.0
Additions for current year tax positions	2.7	30.3	4.0
Additions for prior year positions	15.7	3.4	4.6
Reductions for settlements with tax authorities	(88.5)		
Reductions for expirations of statute of limitations	(3.0)		
Balance at end of period	$ 113.2	$ 186.3	$ 152.6

The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate is $109.2 million. However, $10.4 million would generate a deferred tax asset for state NOL carryforwards that would more likely than not be offset by a valuation allowance. The Company does not expect any significant changes to its net unrecognized tax benefits within 12 months of this reporting date.

The Company s federal income tax returns are under examination by the IRS for the 2005 and 2006 income tax years. The IRS has issued the Company notices of proposed adjustments to decrease the Company s net operating losses associated with the liquidation of an insolvent subsidiary and interest income accrued by a foreign subsidiary. The Company believes its position regarding these matters is supported by applicable valuation methodology, tax laws and existing Treasury regulations. The Company and the IRS have agreed to proceed to an alternative dispute resolution program (Fast Track Settlement) which could facilitate a settlement within 120 days (expected to be May 2010); and, provided a settlement is reached in this process, additional changes could occur to the amount of unrecognized tax benefits. However, the Company does not expect any changes to have a material impact on its financial position or results of operations.

If a settlement is not reached under the Fast Track Settlement process, the Company will begin the formal IRS appeals process to resolve any outstanding issues which could take two or more years to complete. Should the IRS positions ultimately be sustained at the conclusion of the appeals process, additional income tax charges would be required to the extent the Company s net operating loss carryforwards are reduced.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in its income tax provision. The Company has recognized $2.8 million of interest for the year ended December 31, 2009. The Company had $6.4 million and $3.6 million of accrued interest related to uncertain tax positions at December 31, 2009 and 2008, respectively. The Company has considered the application of penalties on its unrecognized tax benefits and determined, based upon several factors, including the existence of NOL carryforwards, that no accrual of penalties is required.

The Company s federal income tax returns for 1999 through 2001, 2003 through 2004 and 2007 through 2008 remain subject to examination by the IRS. The Company s state income tax returns for the tax years 1991 and beyond remain subject to examination by various state taxing authorities. The Company s foreign income tax returns for the tax years 2003 and beyond remain subject to examination by various foreign taxing authorities.

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was approximately $1.4 billion at December 31, 2009 and $1.2 billion at December 31, 2008. The Company has

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

not provided deferred taxes on foreign earnings of $1.3 billion for 2009 and $1.1 billion for 2008 because such earnings were intended to be indefinitely reinvested outside the U.S. Should the Company repatriate all of these earnings, a one-time income tax charge to the Company s consolidated results of operations of up to $466.0 million could occur.

The following table summarizes the Company s tax payments:

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
U.S. federal	$	$	$ 3.0
U.S. state and local	0.9		1.2
Non U.S.	169.7	65.8	80.0
Total tax payments	$ 170.6	$ 65.8	$ 84.2

(12) Long-Term Debt

The Company s total indebtedness as of December 31, 2009 and 2008 consisted of the following:

	December 31,	
	2009	2008
	(Dollars in millions)	
Term Loan under Senior Unsecured Credit Facility	$ 490.3	$ 490.3
Convertible Junior Subordinated Debentures due December 2066	371.5	369.9
7.375% Senior Notes due November 2016	650.0	650.0
6.875% Senior Notes due March 2013	650.0	650.0
7.875% Senior Notes due November 2026	247.1	247.0
5.875% Senior Notes due March 2016	218.1	218.1
6.84% Series C Bonds due December 2016	33.0	43.0
6.34% Series B Bonds due December 2014	15.0	18.0
6.84% Series A Bonds due December 2014		10.0
Capital lease obligations	67.5	81.2
Fair value hedge adjustment	8.4	15.1
Other	1.4	1.0
Total	$ 2,752.3	$ 2,793.6

Senior Unsecured Credit Facility

The Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility (the Revolver) and a $950.0 million Term Loan Facility (the Term Loan) and matures on September 15, 2011. The Revolver is intended to accommodate working capital needs, letters of credit, and other general corporate purposes, and includes a $50.0 million sub-facility available for same-day swingline loan borrowings. As of December 31, 2009, the Company had $315.7 million of letters of credit outstanding under the Revolver, with a remaining available borrowing capacity of approximately $1.5 billion.

Loans under the facility are available to the Company in U.S. dollars, with a sub-facility under the Revolver available in Australian dollars, pounds sterling and euros. Letters of credit under the Revolver are available to the Company in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and euros. The interest rate payable on the Revolver and the Term Loan is based on a pricing grid tied to the Company s leverage ratio, as defined in the Third Amended and Restated Credit Agreement. The interest rate payable on the Revolver and the Term Loan is currently LIBOR plus 0.75%, which was 1.0% at December 31, 2009.

Under the Senior Unsecured Credit Facility, the Company must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio. The financial covenants also place limitations on the Company s investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties and the imposition of liens on Company assets.

Convertible Junior Subordinated Debentures

As of December 31, 2009, the Company had $732.5 million aggregate principal outstanding of Convertible Junior Subordinated Debentures (the Debentures) that generally require interest to be paid semiannually at a rate of 4.75% per year. The Company may elect to, and to the extent that a mandatory trigger event (as defined in the indenture governing the Debentures) has occurred and is continuing will be required to, defer interest payments on the Debentures. After five years of deferral at the Company s option, or upon the occurrence of a mandatory trigger event, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay deferred interest, subject to certain limitations. In no event may the Company defer payments of interest on the Debentures for more than 10 years.

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) the Company s closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $81.75 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of the Company s common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 16) with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with the Company s common stock. As a result of the Patriot spin-off and a change in the Company s dividend distribution rate, the conversion rate was adjusted. The current conversion rate is 17.1244 shares of common stock per $1,000 principal amount of Debentures effective February 8, 2010. This adjusted conversion rate represents a conversion price of approximately $58.40.

The Debentures are not subject to redemption prior to December 20, 2011. Between December 20, 2011 and December 19, 2036 the Company may redeem the Debentures, in whole or in part, if for at least 20 out of the 30 consecutive trading days immediately prior to the date on which notice of redemption is given, the Company s closing common stock price has exceeded 130% of the then applicable conversion price for the Debentures. On or after December 20, 2036, whether or not the redemption condition is satisfied, the Company may redeem the Debentures, in whole or in part. The Company may not redeem any Debentures unless (i) all accrued and unpaid interest on the Debentures has been paid in full on or prior to the redemption date and (ii) if any perpetual preferred stock is outstanding, the Company has first given notice to redeem the perpetual preferred stock in the same proportion as the redemption of the Debentures. Any redemption of the Debentures will be at a cash redemption price of 100% of the principal amount of the Debentures to be redeemed, plus accrued and unpaid interest to the date of redemption.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 15, 2041, the scheduled maturity date, the Company will use commercially reasonable efforts, subject to the occurrence of a market disruption event, as defined in the indenture governing the Debentures, to issue securities of equivalent equity content in an amount sufficient to pay the principal amount of the Debentures, together with accrued and unpaid interest. At the final maturity date of the Debentures on December 15, 2066, the entire principal amount will become due and payable, together with accrued and unpaid interest.

In connection with the issuance of the Debentures, the Company entered into a Capital Replacement Covenant (the CRC). Pursuant to the CRC, the Company covenanted for the benefit of holders of covered debt, as defined in the CRC (currently the Company s 7.875% Senior Notes, issued in the aggregate principal amount of $250.0 million), that neither the Company nor any of its subsidiaries shall repay, redeem or repurchase all or any part of the Debentures on or after December 15, 2041 and prior to December 15, 2046, except to the extent that the total repayment, redemption or repurchase price does not exceed the sum of: (i) 400% of the Company s net cash proceeds from the sale of its common stock and rights to acquire its common stock (including common stock issued pursuant to the Company s dividend reinvestment plan or employee benefit plans); (ii) the Company s net cash proceeds from the sale of its mandatorily convertible preferred stock, as defined in the CRC, or debt exchangeable for equity, as defined in the CRC; and (iii) the Company s net cash proceeds from the sale of other replacement capital securities, as defined in the CRC, in each case, during the six months prior to the notice date for the relevant payment, redemption or repurchase.

The Debentures are unsecured obligations of the Company, ranking junior to all existing and future senior and subordinated debt (excluding trade accounts payable or accrued liabilities arising in the ordinary course of business) except for any future debt that ranks equal to or junior to the Debentures. The Debentures will rank equal in right of payment with the Company s obligations to trade creditors. Substantially all of the Company s existing indebtedness is senior to the Debentures. In addition, the Debentures will be effectively subordinated to all indebtedness of the Company s subsidiaries. The indenture governing the Debentures places no limitation on the amount of additional indebtedness that the Company or any of the Company s subsidiaries may incur.

As discussed in Note 1, the Company adopted an accounting standard such that the Company separately accounts for the liability and equity components of the Debentures in a manner that reflects the nonconvertible debt borrowing rate when recognizing interest cost in subsequent periods. The following table illustrates the carrying amount of the equity and debt components of the Debentures:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Carrying amount of the equity component	$ 215.4	$ 215.4
Principal amount of the liability component	732.5	732.5
Unamortized discount	(361.0)	(362.6)
Net carrying amount	$ 371.5	$ 369.9

The following table illustrates the effective interest rate and the interest expense related to the Debentures:

	Year Ended December 31,		
	2009	**2008**	**2007**
	(Dollars in millions)		
Effective interest rate	4.9%	4.9%	4.9%
Interest expense contractual interest coupon	$ 34.8	$ 34.5	$ 34.9
Interest expense amortization of debt discount	1.6	1.5	1.3

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The remaining period over which the discount will be amortized is 32 years as of December 31, 2009.

7.375% Senior Notes and 7.875% Senior Notes

The notes are general unsecured obligations of the Company and rank senior in right of payment to any subordinated indebtedness of the Company; equally in right of payment with any senior indebtedness of the Company; effectively junior in right of payment to the Company s existing and future secured indebtedness, to the extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of the Company s subsidiaries that do not guarantee the notes. Interest payments are scheduled to occur on May 1 and November 1 of each year.

The notes are guaranteed by the Company s Subsidiary Guarantors, as defined in the note indenture. The note indenture contains covenants that, among other things, limit the Company s ability to create liens and enter into sale and lease-back transactions. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole premium, if applicable, and any accrued unpaid interest to the redemption date.

6.875% Senior Notes

The notes are senior unsecured obligations of the Company and rank equally with all of the Company s other senior unsecured indebtedness. Interest payments are scheduled to occur on March 15 and September 15 of each year. The notes are guaranteed by the Company s Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit the Company s ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable at fixed redemption prices as set forth in the indenture.

5.875% Senior Notes

The notes are senior unsecured obligations of the Company and rank equally with all of the Company s other senior unsecured indebtedness. Interest payments are scheduled to occur on April 15 and October 15 of each year. The notes are guaranteed by the Company s Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit the Company s ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable at fixed redemption prices as set forth in the indenture.

Series Bonds

The Series Bonds were assumed as part of the Excel acquisition. In December 2009, the Company purchased $20.0 million of the bonds in an open market transaction for $19.0 million resulting in a $1.0 million gain that was recorded as a component of interest expense. The purchase included $10.0 million of the 6.84% Series A Bonds and $10.0 million of the 6.84% Series C Bonds. Based on this purchase, the 6.84% Series A Bonds were paid in full. The 6.34% Series B Bonds are payable in installments. The first scheduled payment occurred in December 2008. The

6.84% Series C Bonds are payable in installments beginning December 2012. Interest payments are scheduled to occur in June and December of each year. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole premium, if applicable, and any accrued unpaid interest to the redemption date.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swaps

As of December 31, 2009, the Company had the following fixed-to-floating and floating-to-fixed interest rate swaps:

	Notional Amount	Benefit Received	Amount Paid (Dollars in millions)	Termination Date	Fair Value
Fixed to Floating					
67/8 $650 Senior Notes	$ 25.0	6.875% semi-annually	6-M LIBOR + 299.75 bps semi-annually	3/15/2013	$ 0.8
67/8 $650 Senior Notes	$ 25.0	6.875% semi-annually	6-M LIBOR + 307 bps semi-annually	3/15/2013	$ 0.7
Floating to Fixed					
Senior Unsecured Term Loan	$ 120.0	3-M LIBOR + 100 bps quarterly	6.25% semi-annually	9/15/2011	$ (9.8)

Legend: M = month; bps = basis points

Because the critical terms of the swaps and the respective debt instruments they hedge coincide, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2009, 2008, or 2007. At December 31, 2009 and 2008, there was an unrealized loss related to the cash flow hedge of $9.8 million and $21.8 million, respectively. At December 31, 2009 and 2008, there was a net unrealized gain on the fair value hedges of $8.4 million and $15.1 million, respectively. The fair value hedge adjustment, which includes the unamortized portion of terminated fair value hedges ($6.9 million and $2.6 million at December 31, 2009 and 2008, respectively), is reflected as an adjustment to the carrying value of the 6.875% Senior Notes.

Capital Lease Obligations

Capital lease obligations are primarily for mining equipment (see Note 9 for additional information on the Company s capital lease obligations).

Debt Maturities, Interest Paid, and Financing Costs

The aggregate amounts of long-term debt maturities (excluding unamortized debt discounts) subsequent to December 31, 2009, including capital lease obligations, were as follows (Dollars in millions):

Year of Maturity	
2010	$ 14.1

2011	505.2
2012	22.1
2013	689.5
2014	21.5
2015 and thereafter	1,863.8
Total	$ 3,116.2

Interest paid on long-term debt was $201.6 million, $226.0 million and $191.9 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Financing costs incurred with the issuance of the Company s debt are being amortized to interest expense over the remaining term of the associated debt. The remaining balance at December 31, 2009 was $30.6 million, of which $17.9 million will be amortized to interest expense over the next five years.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(13) Asset Retirement Obligations

Reconciliations of the Company s ARO liability are as follows:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Balance at beginning of year	$ 418.7	$ 360.7
Liabilities incurred or acquired	0.4	
Liabilities settled or disposed	(8.1)	(6.1)
Accretion expense	24.0	20.5
Revisions to estimates	17.1	43.6
Balance at end of year	$ 452.1	$ 418.7
Balance at end of year active locations	$ 422.0	$ 383.3
Balance at end of year closed or inactive locations	$ 30.1	$ 35.4

The credit-adjusted, risk-free interest rates were 7.92% at December 31, 2009 and 7.91% at December 31, 2008 and 7.85% at January 1, 2008.

As of December 31, 2009 and 2008, the Company had $772.3 million and $740.6 million, respectively, in surety bonds outstanding to secure reclamation obligations or activities. The amount of reclamation self-bonding in certain states in which the Company qualifies was $821.9 million and $773.4 million as of December 31, 2009 and 2008, respectively. Additionally, the Company had $34.9 million and $0.1 million of letters of credit in support of reclamation obligations or activities as of December 31, 2009 and 2008, respectively.

(14) Pension and Savings Plans

One of the Company s subsidiaries, Peabody Investments Corp. (PIC), sponsors a defined benefit pension plan covering certain U.S. salaried employees and eligible hourly employees at certain PIC subsidiaries (the Peabody Plan). A PIC subsidiary also has a defined benefit pension plan covering eligible employees who are represented by the UMWA under the Western Surface Agreement (the Western Plan). PIC also sponsors an unfunded supplemental retirement plan to provide senior management with benefits in excess of limits under the federal tax law. These plans are collectively referred to as The Plans.

Effective June 1, 2008 the Peabody Plan was frozen in its entirety for both participation and benefit accrual purposes. The Company adopted an enhanced savings plan contribution structure in lieu of benefits formerly accrued under the Peabody Plan.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic pension cost included the following components:

	Year Ended December 31, 2009	2008	2007
	(Dollars in millions)		
Service cost for benefits earned	$ 1.4	$ 2.0	$ 12.7
Interest cost on projected benefit obligation	51.3	51.0	49.0
Expected return on plan assets	(60.9)	(60.6)	(57.4)
Amortization of prior service cost	1.4	1.3	0.4
Amortization of actuarial (gains) losses	1.9	(0.5)	15.3
Net periodic pension cost	(4.9)	(6.8)	20.0
Curtailment gain		(0.6)	(0.4)
Total net periodic pension (benefit) cost	$ (4.9)	$ (7.4)	$ 19.6

The following includes amounts recognized in accumulated other comprehensive loss:

	Year Ended December 31, 2009	2008	2007
	(Dollars in millions)		
Net actuarial (gain) loss arising during year	$ 46.1	$ 199.2	$ (89.6)
Prior service cost arising during year			7.9
Amortizations:			
Actuarial gain (loss)	(1.9)	0.5	(15.3)
Prior service cost	(1.4)	(0.7)	
Total recognized in other comprehensive loss	42.8	199.0	(97.0)
Net periodic pension (benefit) costs	(4.9)	(6.8)	20.0
Total recognized in net periodic pension cost and other comprehensive loss	$ 37.9	$ 192.2	$ (77.0)

The Company amortizes actuarial gains and losses using a 5% corridor with a five-year amortization period. The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive loss into net periodic pension costs during the year ended December 31, 2010 are $21.9 million and $1.4 million, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following summarizes the change in benefit obligation, change in plan assets and funded status of the Company s plans:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$ 768.6	$ 778.2
Service cost	1.4	2.0
Interest cost	51.3	51.0
Benefits paid	(48.3)	(46.7)
Actuarial (gain) loss	71.9	(15.9)
Projected benefit obligation at end of period	844.9	768.6
Change in plan assets:		
Fair value of plan assets at beginning of period	552.6	732.4
Actual return on plan assets	86.6	(154.4)
Employer contributions	38.7	21.3
Benefits paid	(48.3)	(46.7)
Fair value of plan assets at end of period	629.6	552.6
Funded status at end of year	$ (215.3)	$ (216.0)
Amounts recognized in the consolidated balance sheets:		
Current obligation (included in Accounts payable and accrued expenses)	$ (1.8)	$ (1.6)
Noncurrent obligation (included in Other noncurrent liabilities)	(213.5)	(214.4)
Net amount recognized	$ (215.3)	$ (216.0)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	Year Ended December 31, 2009	Year Ended December 31, 2008
Discount rate	6.19%	6.90%
Rate of compensation increase	N/A	N/A
Measurement date	December 31, 2009	December 31, 2008

The weighted-average assumptions used to determine net periodic benefit cost were as follows:

	Year Ended December 31,		
	2009	2008	2007
Discount rate	6.90%	6.75%	6.00%
Expected long-term return on plan assets	8.75%	8.75%	8.75%
Rate of compensation increase	N/A	N/A	3.50%
Measurement date	December 31, 2008	December 31, 2007	December 31, 2006

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class (net of inflation) based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effective January 1, 2010, the Company lowered its expected rate of return on plan assets from 8.75% to 8.25% given the decline in asset performance due to the global recession and disruption in the financial markets, as well as management s reevaluation of the ongoing impact of active management of assets by outside investment advisors.

The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for all plans as of December 31, 2009 and 2008. The accumulated benefit obligation for all pension plans was $844.9 million and $768.6 million as of December 31, 2009, and 2008, respectively.

Assets of the Plans

Assets of the Peabody Plan and the Western Plan are commingled in the PIC Master Trust (the Master Trust) and are invested in accordance with investment guidelines that have been established by the Company s Retirement Committee (the Retirement Committee) after consultation with outside investment advisors and actuaries.

The asset allocation targets have been set with the expectation that the Plans assets will be managed with an appropriate level of risk so that they can fund each Plan s expected liabilities. To determine the appropriate target asset allocations, the Retirement Committee considers the demographics of each Plan s participants, the funding status of each Plan, the business and financial profile of the Company and other associated risk preferences. These allocation targets are reviewed by the Retirement Committee on a regular basis and revised as necessary. The current target allocations for plan assets are 55% equity securities, 35% fixed income investments and 10% real estate investments. The Company plans to transition to 60% equity securities and 40% fixed income investments over time.

Assets of the Plans are either under active management by third-party investment advisors or in index funds, all selected and monitored by the Retirement Committee. The Retirement Committee has established specific investment guidelines for each major asset class including performance benchmarks, allowable and prohibited investment types and concentration limits. In general, the Plans investment guidelines do not permit leveraging the assets held in the Master Trust. Equity investment guidelines do not permit entering into put or call options (except as deemed appropriate to manage currency risk), and futures contracts are permitted only to the extent necessary to equitize cash holdings.

The following table presents the fair value of assets in the Master Trust by category and by fair value valuation hierarchy:

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
U.S. equity securities	$ 68.1	$ 200.2	$	$ 268.3
International equity securities		102.2		102.2
Mortgage-backed debt securities		77.5		77.5
U.S. debt securities	10.5	35.3		45.8
International debt securities		19.2		19.2

Corporate debt securities		37.2		37.2
Short-term investments		32.0		32.0
Interests in real estate			47.4	47.4
Total assets at fair value	$ 78.6	$ 503.6	$ 47.4	$ 629.6

A financial instrument s level within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for investments measured at fair value, including the general classification of such investments pursuant to the valuation hierarchy.

U.S. equity securities. Investment vehicles include various small-cap publicly traded common stocks, an exchange-traded fund and a common collective trust. Publicly traded common stocks and the exchange-traded fund are traded on a national securities exchange and are valued at quoted market prices in active markets and are classified within Level 1 of the valuation hierarchy. While the common collective trust invests in various large-cap publicly traded common stocks that are traded on a national securities exchange, it is classified within Level 2 of the valuation hierarchy since the net asset value (NAV) is based on a derived price in an active market and it is not publicly traded on a national securities exchange.

International equity securities. Investment vehicles include a common collective trust and an investment entity that primarily invest in various large-cap international equity securities that are valued on the basis of quotations from the primary market in which they are traded and translated at each valuation date from the local currency into U.S. dollars using the mean between the bid and asked market rates for such currencies. The NAV of the fund and the calculation of the NAV of each underlying investment is determined in U.S. dollars by the custodial trustee or at the direction of the investment manager as of the end of each month. These investments are classified within the Level 2 valuation hierarchy since the NAV is based on a derived price in an active market and neither the common collective trust nor the investment entity are publicly traded on a national securities exchange.

Debt securities. Investment vehicles for U.S debt securities, mortgage-backed debt securities, international debt securities and corporate debt securities (collectively, debt securities) primarily consist of mutual funds, which are invested in various diversified portfolios of fixed-income instruments. NAV for each debt security is calculated daily in actively traded markets by an independent custodian for the investment manager. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Market value is generally determined on the basis of last reported sales prices, or if no sales are reported, based on quotes obtained from a quotation reporting system, established market makers, or pricing services. Investments initially valued in currencies other than the U.S. dollar are converted to the U.S. dollar using exchange rates obtained from pricing services. Since the fair value inputs are derived prices in active markets and the mutual funds are not publicly traded on a national securities exchange, the debt securities are classified within the Level 2 valuation hierarchy.

Short-term investments. Investments primarily consist of a common collective trust that invests in commercial paper, repurchase agreements, time deposits and agency discount notes. Units in the common collective trust are valued at NAV at year-end. These investments are classified within Level 2 of the valuation hierarchy as the NAV for these investments is a derived price in an active market and the common collective trust is not publicly traded on a national securities exchange.

Interests in real estate. Investments in real estate represent interests in real estate pooled funds and limited partnerships, which consist of net partnership interests in properties. They are valued using various methodologies including independent third party appraisals. For some investments little market activity may exist and determination of fair value is then based on the best information available in the circumstances. This involves a significant degree of judgment by taking into consideration a combination of internal and external factors. Based on the above factors, the real estate funds are classified within the Level 3 valuation hierarchy.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Company believes the valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. The inputs or methodology used for valuing investments are not necessarily an indication of the risk associated with investing in those investments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The table below sets forth a summary of changes in the fair value of the Master Trust s Level 3 investments.

Interests in Real Estate	**Year Ended December 31, 2009 (Dollars in millions)**
Beginning of year	$ 62.2
Assets held at the reporting date:	
Realized gains	1.5
Unrealized losses	(21.5)
Purchases, sales and settlements, net	6.2
Transfers out of Level 3	(1.0)
End of year	$ 47.4

Contributions

Annual contributions to the Plans are made as determined by consulting actuaries based upon the Employee Retirement Income Security Act of 1974 minimum funding standard. In May 1998, the Company entered into an agreement with the Pension Benefit Guaranty Corporation (PBGC) which requires the Company to maintain certain minimum funding requirements. Effective January 1, 2008, new minimum funding standards were required by the Pension Protection Act of 2006 (the Pension Protection Act) that increased the long-term funding targets for single employer pension plans from 90% to 100%. At risk plans, as defined by the Pension Protection Act, are restricted from making full lump sum payments and from increasing benefits unless they are funded immediately, and also requires that the plan give participants notice regarding the at-risk status of the plan. If a plan falls below 60%, lump sum payments are prohibited and benefit accruals cease.

As of December 31, 2009, the Company s qualified pension plans were approximately 77% funded (on a GAAP accounting basis), before considering planned 2010 contributions of $3.4 million, which represents the 2010 minimum funding requirement for the qualified Plans.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Master Trust:

	Pension Benefits (Dollars in millions)
2010	$ 53.9
2011	55.4

2012	56.9
2013	58.8
2014	61.0
Years 2015-2019	327.1

Defined Contribution Plans

The Company sponsors employee retirement accounts under three 401(k) plans for eligible U.S. employees. The Company matches voluntary contributions to each plan up to specified levels. The expense for these plans was $47.9 million, $50.5 million and $21.7 million for the years ended December 31, 2009, 2008 and 2007, respectively. A performance contribution feature allows for additional contributions from the Company

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

based upon meeting specified Company performance targets. Performance contributions related to the years ended December 31, 2009, 2008, and 2007 were $20.3 million, $18.7 million and $4.9 million, respectively.

Multi-Employer Pension Plan Discontinued Operations

Certain subsidiaries that were part of the Patriot spin-off participate in multi-employer pension plans (the 1950 Plan and the 1974 Plan), which provide defined benefits to substantially all hourly coal production workers represented by the UMWA under the 2007 NBCWA. During 2007, contributions of $5.9 million made to the 1974 Plan were expensed as paid, and are reflected in Discontinued operations. There were no contributions to the multi-employer pension plans during the years ended December 31, 2009 and 2008.

(15) Postretirement Health Care and Life Insurance Benefits

The Company currently provides health care and life insurance benefits to qualifying salaried and hourly retirees and their dependents from defined benefit plans established by the Company. Plan coverage for health and life insurance benefits is provided to future hourly retirees in accordance with the applicable labor agreement.

Net periodic postretirement benefit cost included the following components:

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Service cost for benefits earned	$ 10.5	$ 10.1	$ 9.4
Interest cost on accumulated postretirement benefit obligation	55.2	54.0	50.6
Amortization of prior service cost (credit)	1.5	0.4	(0.2)
Amortization of actuarial losses	14.5	17.3	22.8
Net periodic postretirement benefit cost	$ 81.7	$ 81.8	$ 82.6

Net periodic postretirement benefit cost related to the spin-off of Patriot was $46.6 million for the year ended December 31, 2007 and was included in Discontinued operations.

The following includes amounts recognized in accumulated other comprehensive loss:

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Net actuarial (gain) loss arising during year	$ 165.2	$ (18.3)	$ (24.5)
Prior service cost arising during year	(10.5)		13.8

Amortizations:			
Actuarial loss	(14.5)	(17.3)	(22.8)
Prior service (cost) credit	(1.5)	(0.4)	0.2
Total recognized in other comprehensive loss	138.7	(36.0)	(33.3)
Net periodic postretirement benefit cost	81.7	81.8	82.6
Total recognized in net periodic postretirement benefit costs and other comprehensive loss	$ 220.4	$ 45.8	$ 49.3

The Company amortizes actuarial gains and losses using a 0% corridor with an amortization period that covers the average remaining service period of active employees (10.92 years and 10.68 years at January 1, 2009 and 2008, respectively). The estimated net actuarial loss and prior service cost that will be amortized

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

from accumulated other comprehensive loss into net periodic postretirement benefit cost during the year ended December 31, 2010 are $25.4 million and $2.0 million, respectively.

The following table sets forth the plan s funded status reconciled with the amounts shown in the consolidated balance sheets:

	December 31, 2009	December 31, 2008
	(Dollars in millions)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of period	$ 833.4	$ 855.8
Service cost	10.5	10.1
Interest cost	55.2	54.0
Participant contributions	1.2	1.5
Plan amendments[1]	(10.5)	
Benefits paid	(72.8)	(69.7)
Actuarial (gain) loss	165.2	(18.3)
Accumulated postretirement benefit obligation at end of period	982.2	833.4
Change in plan assets:		
Fair value of plan assets at beginning of period		
Employer contributions	71.6	68.2
Participant contributions	1.2	1.5
Benefits paid and administrative fees (net of Medicare Part D reimbursements)	(72.8)	(69.7)
Fair value of plan assets at end of period		
Funded status at end of year	(982.2)	(833.4)
Less current portion (included in Accounts payable and accrued expenses)	68.1	67.3
Noncurrent obligation (included in Accrued postretirement benefit costs)	$ (914.1)	$ (766.1)

[1] Effective January 1, 2010, the benefits provided to certain salaried retirees are capped at a fixed level, which resulted in a decrease to the retiree health care liability of $7.3 million. The Company will begin realizing the effect of this plan amendment over 13.54 years beginning January 1, 2010.

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	Year Ended December 31, 2009	2008
Discount rate	6.14%	6.85%
Rate of compensation increase	3.50%	3.50%
Measurement date	December 31, 2009	December 31, 2008

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted-average assumptions used to determine net periodic benefit cost were as follows:

	Year Ended December 31, 2009	2008	2007
Discount rate	6.85%	6.60%	6.00%
Rate of compensation increase	3.50%	3.50%	3.50%
Measurement date	December 31, 2008	December 31, 2007	December 31, 2006

The following presents information about the assumed health care cost trend rate:

	Year Ended December 31, 2009	2008
Health care cost trend rate assumed for next year	7.50%	7.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	4.75%
Year that the rate reaches the ultimate trend rate	2016	2014

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in the assumed health care cost trend would have the following effects:

	One Percentage-Point Increase	One Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components	$ 6.7	$ (5.7)
Effect on total postretirement benefit obligation	$ 98.3	$ (84.6)

Plan Assets

The Company s postretirement benefit plans are unfunded.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service as appropriate, are expected to be paid by the Company:

	Postretirement Benefits (Dollars in millions)

2010	$ 68.1
2011	70.7
2012	74.5
2013	75.9
2014	77.1
Years 2015-2019	398.3

Multi-Employer Benefit Plans Discontinued Operations

Multi-employer benefit obligations related to the Combined Fund, the 1992 Benefit Plan and 1993 Benefit Plan became the responsibility of Patriot in conjunction with the spin-off. The Surface Mining Control and Reclamation Act Amendments of 2006 amended the federal laws establishing the Combined Fund and the 1992 Benefit Plan and include the 1993 Benefit Plan. To the extent that (i) the annual federal funding is less than benefits paid, (ii) Congress does not allocate additional funds to cover the shortfall and (iii) Patriot s subsidiaries do not pay for their share of the shortfall, some of the Company s subsidiaries would be

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

responsible for the additional costs. The total expense for the Combined Fund, the 1992 Benefit Plan and 1993 Benefit Plan was $14.5 million for the year ended December 31, 2007 and was included in Discontinued operations.

(16) Stockholders Equity

Common Stock

The Company has 800.0 million authorized shares of $0.01 par value common stock. Holders of common stock are entitled to one vote per share on all matters to be voted upon by the stockholders and vote together, as one class, with the holders of the Company s Series A Junior Participating Preferred Stock, if any such shares were issued and outstanding. The holders of common stock do not have cumulative voting rights in the election of directors. Holders of common stock are entitled to receive ratably dividends if, as and when dividends are declared from time to time by the Company s Board of Directors out of funds legally available for that purpose, after payment of dividends required to be paid on outstanding preferred stock or series common stock, as described below. Upon liquidation, dissolution or winding up, any business combination or a sale or disposition of all or substantially all of the assets, the holders of common stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and accrued but unpaid dividends and liquidation preferences on any outstanding preferred stock or series common stock. The common stock has no preemptive or conversion rights and is not subject to further calls or assessment by the Company. There are no redemption or sinking fund provisions applicable to the common stock.

The following table summarizes common stock activity from December 31, 2006 to December 31, 2009:

	Shares Outstanding
December 31, 2006	**263,846,839**
Stock options exercised	5,222,074
Stock grants to employees	937,795
Employee stock purchases	185,646
Stock grants to non-employee directors	11,892
Shares relinquished	(137,625)
December 31, 2007	**270,066,621**
Stock options exercised	1,388,174
Stock grants to employees	788,895
Employee stock purchases	119,737
Stock grants to non-employee directors	2,870
Shares repurchased	(5,524,574)
Shares relinquished	(196,744)
December 31, 2008	**266,644,979**
Stock options exercised	463,490
Stock grants to employees	794,213

Employee stock purchases	374,548
Stock grants to non-employee directors	4,788
Shares relinquished	(78,203)
December 31, 2009	**268,203,815**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Preferred Stock and Series Common Stock

The Board of Directors is authorized to issue up to 10.0 million shares of preferred stock and up to 40.0 million shares of series common stock. The Board of Directors can determine the terms and rights of each series, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates, and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company. The Board of Directors may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of preferred stock or series common stock as of December 31, 2009.

Perpetual Preferred Stock

As discussed in Note 12, the Company had $732.5 million aggregate principal amount of Debentures outstanding as of December 31, 2009. Perpetual preferred stock issued upon a conversion of the Debentures will be fully paid and non-assessable, and holders will have no preemptive or preferential right to purchase any of the Company s other securities. The perpetual preferred stock has a liquidation preference of $1,000 per share, is not convertible and is redeemable at the Company s option at any time at a cash redemption price per share equal to the liquidation preference plus any accumulated dividends. Holders are entitled to receive cumulative dividends at an annual rate of 3.0875% if and when declared by the Company s Board of Directors. If the Company fails to pay dividends on the perpetual preferred stock for five years, or upon the occurrence of a mandatory trigger event, as defined in the certificate of designations governing the perpetual preferred stock, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay accumulated dividends after the payment in full of any deferred interest on the Debentures, subject to certain limitations. In the event of a mandatory trigger event, the Company may not declare dividends on the perpetual preferred stock other than those funded through the sale of warrants or preferred stock as described above. Any deferred interest on the Debentures at the time of notice of conversion will be reflected as accumulated dividends on the perpetual preferred stock at issuance. Additionally, holders of the perpetual preferred stock are entitled to elect two additional members to serve on the Company s Board of Directors if (i) prior to any remarketing of the perpetual preferred stock, the Company fails to declare and pay dividends with respect to the perpetual stock for 10 consecutive years or (ii) after any successful remarketing or any final failed remarketing of the perpetual preferred stock, the Company fails to declare and pay six dividends thereon, whether or not consecutive. The perpetual preferred stock may be remarketed at the holder s election after December 15, 2046 or earlier, upon the first occurrence of a change of control if the Company does not redeem the perpetual preferred stock. There were no outstanding shares of perpetual preferred stock as of December 31, 2009.

Preferred Share Purchase Rights Plan and Series A Junior Participating Preferred Stock

Each outstanding share of common stock, par value $0.01 per share, of the Company carries one preferred share purchase right (a Right). The Rights are governed by a plan that expires in August 2012.

The Rights have certain anti-takeover effects. The Rights will cause substantial dilution to a person or group that attempts to acquire the Company on terms not approved by the Company s Board of Directors, except pursuant to any offer conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any merger or other business combination approved by the Board of Directors since the Rights may be redeemed by the Company at a redemption price of $0.001 per Right prior to the time that a person or group has acquired beneficial ownership of 15% or more of the common stock of the Company. In addition, the Board of Directors is authorized to reduce the 15% threshold to not less than 10%.

Each Right entitles the holder to purchase one quarter of one-hundredth of a share of Series A Junior Participating Preferred Stock from the Company at an exercise price of $27.50, which in turn provides rights

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to receive the number of common stock shares having a market value of two times the exercise price of the Right. The Right is exercisable only if a person or group acquires 15% or more of the Company s common stock. The Board of Directors is authorized to issue up to 1.5 million shares of Series A Junior Participating Preferred Stock. There were no outstanding shares of Series A Junior Participating Preferred Stock as of December 31, 2009.

Treasury Stock

The Company has a share repurchase program for its common stock with an authorized amount of $1 billion in which repurchases may be made from time to time based on an evaluation of the Company s outlook and general business conditions, as well as alternative investment and debt repayment options. The Company s Chairman and Chief Executive Officer also has authority to direct the Company to repurchase up to $100 million of 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, 2009, the Company has made repurchases of 7.7 million shares at a cost of $299.6 million, leaving $700.4 million available for share repurchase under the program.

During the year ended December 31, 2009, the Company received 78,203 shares of common stock to pay estimated taxes as consideration for the exercise of stock options, the payout of performance units and the vesting of restricted stock. The value of the common stock tendered by employees was based upon the closing price on the dates of the respective transactions.

(17) Share-Based Compensation

The Company recognizes share-based compensation expense in accordance with the fair value recognition provisions of Compensation topic of the ASC, which it adopted on January 1, 2006. The Company has four equity incentive plans for employees and non-employee directors that in the aggregate allow for the issuance of share-based compensation in the form of stock appreciation rights, restricted stock, performance awards, incentive stock options, nonqualified stock options and deferred stock units. These plans made 47.4 million shares of the Company s common stock available for grant, with 14.6 million shares available for grant as of December 31, 2009. The Company has two employee stock purchase plans that provide for the purchase of up to 6.0 million shares of the Company s common stock, with 5.0 million shares authorized for purchase by U.S. employees and 1.0 million shares authorized for purchase by the Australian employees.

Share-based compensation expense, which is recorded in Selling and administrative expenses in the consolidated statements of operations, was as follows (Dollars in millions):

Year Ended December 31,	Total Expense	Tax Benefit	Expense, Net of Tax Benefit
2009	$ 38.8	$ 15.0	$ 23.8
2008	34.9	13.5	21.4
2007	20.1	2.9	17.2

As of December 31, 2009, the total unrecognized compensation cost related to nonvested awards was $28.0 million, net of taxes, which is expected to be recognized over 3.2 years with a weighted-average period of 0.7 years.

In 2009 and 2008, the Company granted deferred stock units to each of its non-employee directors. The fair value of these units are equal to the market price of the Company s common stock at the date of grant and generally vest after one year. In 2007, the Company granted stock options and restricted stock to each of its non-employee directors.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock Awards

Restricted stock awards are typically granted in January of each year and generally cliff vest after three years of service. The fair value of restricted stock is equal to the market price of the Company s common stock at the date of grant and is amortized to expense ratably over the vesting period.

A summary of restricted stock award activity is as follows:

	Year Ended December 31, 2009	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2009	1,788,333	$ 38.13
Granted	769,229	30.09
Vested	(308,760)	36.43
Forfeited	(103,937)	37.49
Nonvested at December 31, 2009	2,144,865	$ 35.51

Stock Options

Employee and director stock options granted since the Company s initial public offering (IPO) of common stock in May 2001 generally vest ratably over three years and expire after 10 years from the date of the grant, subject to earlier termination upon discontinuation of an employee s service. Options granted prior to the IPO generally cliff vest in 2010 and represented 0.8 million options of the 3.2 million options outstanding at December 31, 2009. Option grants are typically made in January of each year or following the inception of employment for employees hired during the year who are eligible to participate in the plan.

The Company used the Black-Scholes option pricing model to determine the fair value of stock options. The Company utilized U.S. Treasury yields as of the grant date for its risk-free interest rate assumption, matching the treasury yield terms to the expected life of the option. The Company utilized historical company data to develop its dividend yield, expected volatility and expected option life assumptions.

A summary of outstanding option activity under the plans is as follows:

	Year Ended December 31,	Weighted Average Exercise	Weighted Average Remaining Contractual	Aggregate Intrinsic

	2009	Price	Life	Value (In millions)
Options Outstanding at January 1, 2009	3,250,857	$ 17.84		
Granted	481,498	26.84		
Exercised	(463,490)	7.73		
Forfeited	(22,835)	43.37		
Options Outstanding at December 31, 2009	3,246,030	$ 20.44	4.7	$ 85.1
Vested and Exercisable	1,715,557	$ 20.78	4.6	$ 43.1

During the years ended December 31, 2009, 2008 and 2007, the total intrinsic value of options exercised, defined as the excess fair value of the underlying stock over the exercise price of the options, was $14.7 million, $72.8 million and $248.7 million, respectively. The weighted-average fair values of the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s stock options and the assumptions used in applying the Black-Scholes option pricing model (for grants during the years ended December 31, 2009, 2008 and 2007) were as follows:

	December 31, 2009	2008	2007
Weighted-average fair value	$ 26.84	$ 64.31	$ 37.93
Risk-free interest rate	1.5%	3.3%	4.6%
Expected option life	5.0 years	5.0 years	5.0 years
Expected volatility	60%	40%	43%
Dividend yield	0.9%	0.5%	0.6%

Performance Units

Performance units are typically granted annually in January and vest over a three-year measurement period. Prior to 2009, the performance units were usually subject to the achievement of two goals, 50% based on stock price performance compared to both an industry peer group and a S&P index (market condition) and 50% based on a return on capital target (performance condition). For 2009, the units granted were only subject to the achievement of the market condition. Three performance unit grants are outstanding for any given year. The payouts related to all active grants will be settled in the Company s common stock.

A summary of performance unit activity is as follows:

	Year Ended December 31, 2009	Weighted Average Remaining Contractual Life
Nonvested at January 1, 2009	250,691	1.5
Granted	248,263	
Forfeited	(9,195)	
Vested	(133,315)	
Nonvested at December 31, 2009	356,444	1.5

As of December 31, 2009, there were 133,315 performance units vested that had an aggregate intrinsic value of $8.7 million and a conversion price per share of $44.49.

The awards settled are accounted for based on their grant date fair value. The performance condition awards were valued utilizing the grant date fair values of the Company s stock adjusted for dividends foregone during the vesting period. The market condition awards were valued utilizing a Monte Carlo simulation which incorporates the total stockholder return hurdles set for each grant. The assumptions used in the valuations for grants during the years ended December 31, 2009 and 2008 were as follows:

	December 31, 2009	December 31, 2008
Risk-free interest rate	1.3%	2.9%
Expected volatility	60%	40%
Dividend yield	0.9%	0.5%

Employee Stock Purchase Plans

The Company s eligible full-time and part-time employees are able to contribute up to 15% of their base compensation into the employee stock purchase plans, subject to a limit of $25,000 per person per year.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Employees are able to purchase Company common stock at a 15% discount to the lower of the fair market value of the Company s common stock on the initial or final trading dates of each six-month offering period. Offering periods begin on January 1 and July 1 of each year. The Company uses the Black-Scholes option pricing model to determine the fair value of employee stock purchase plans share-based payments. The fair value of the six-month look-back option in the Company s employee stock purchase plans is estimated by adding the fair value of 0.15 of one share of stock to the fair value of 0.85 of an option on one share of stock. The Company utilized U.S. Treasury yields as of the grant date for its risk-free interest rate assumption, matching the treasury yield terms to the six-month offering period. The Company utilized historical company data to develop its dividend yield and expected volatility assumptions.

Shares purchased under the plans were 0.3 million for the year ended December 31, 2009, 0.1 million for the year ended December 31, 2008 and 0.2 million for the year ended December 31, 2007.

(18) Accumulated Other Comprehensive Income (Loss)

The following table sets forth the after-tax components of comprehensive income (loss):

	Foreign Currency Translation Adjustment	Net Actuarial Loss Associated with Postretirement Plans and Workers Compensation Obligations	Prior Service Cost Associated with Postretirement Plans	Cash Flow Hedges	Total Accumulated Other Comprehensive Loss
	(Dollars in millions)				
December 31, 2006	$ 3.1	$ (288.8)	$ (7.0)	$ 43.5	$ (249.2)
Net increase in value of cash flow hedges				83.7	83.7
Reclassification from other comprehensive income to earnings:					
Continuing operations		24.3	(0.1)	(61.8)	(37.6)
Discontinued operations		17.9	(6.1)		11.8
Current period change		64.2	(13.0)		51.2
Patriot spin-off		65.7	7.3		73.0
December 31, 2007	3.1	(116.7)	(18.9)	65.4	(67.1)
				(194.5)	(194.5)

Net decrease in value of cash flow hedges					
Reclassification from other comprehensive income to earnings		14.1	0.2	(23.4)	(9.1)
Current period change		(117.8)			(117.8)
December 31, 2008	3.1	(220.4)	(18.7)	(152.5)	(388.5)
Net increase in value of cash flow hedges				235.2	235.2
Reclassification from other comprehensive income to earnings		11.8	1.8	84.6	98.2
Current period change		(128.4)			(128.4)
December 31, 2009	$ 3.1	$ (337.0)	$ (16.9)	$ 167.3	$ (183.5)

Comprehensive income (loss) differs from net income by the amount of unrealized gain or loss resulting from valuation changes of the Company s cash flow hedges (which include fuel and explosives hedges,

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

currency forwards, traded coal index contracts and interest rate swaps) and the change in actuarial loss and prior service cost during the periods. The values of the Company s cash flow hedging instruments are affected by changes in interest rates, crude oil, diesel fuel, natural gas and coal prices and the U.S. dollar/Australian dollar exchange rate. The change in the value of the cash flow hedges during 2009 was primarily due to the strengthening of the Australian dollar against the U.S. dollar.

(19) Guarantees and Financial Instruments With Off-Balance-Sheet Risk

In the normal course of business, the Company is a party to guarantees and financial instruments with off-balance-sheet risk, such as bank letters of credit, performance or surety bonds and other guarantees and indemnities, which are not reflected in the accompanying consolidated balance sheets. Such financial instruments are valued based on the amount of exposure under the instrument and the likelihood of required performance. In the Company s past experience, virtually no claims have been made against these financial instruments. Management does not expect any material losses to result from these guarantees or off-balance-sheet instruments.

Letters of Credit and Bonding

The Company has letters of credit, surety bonds and corporate guarantees (such as self bonds) in support of the Company s reclamation, coal lease obligations, and workers compensation as follows as of December 31, 2009:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other(1)	Total
			(Dollars in millions)		
Self bonding	$ 821.9	$	$	$	$ 821.9
Surety bonds	772.3	116.3	8.7	57.3	954.6
Letters of credit	34.9		43.0	237.8	315.7
	$ 1,629.1	$ 116.3	$ 51.7	$ 295.1	$ 2,092.2

(1) Other includes the six letter of credit obligations described below and an additional $61.1 million in letters of credit and surety bonds related to collateral for surety companies, road maintenance, performance guarantees and other operations.

The Company owns a 37.5% interest in Dominion Terminal Associates, a partnership that operates a coal export terminal in Newport News, Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The partners have severally (but not jointly) agreed to make payments under various agreements which in the aggregate provide the partnership with sufficient funds to pay rents and to cover the principal and interest payments on the floating-rate industrial revenue bonds issued by the Peninsula Ports Authority, and which are supported by letters of credit from a commercial bank. As of December 31, 2009, the

Company s maximum reimbursement obligation to the commercial bank was in turn supported by four letters of credit totaling $42.7 million.

The Company is party to an agreement with the PBGC and TXU Europe Limited, an affiliate of the Company s former parent corporation, under which the Company is required to make special contributions to two of the Company s defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If the Company or the PBGC gives notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if the Company fails to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employee Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guarantee in place from TXU Europe Limited in favor of the PBGC before it

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draws on the Company s letter of credit. On November 19, 2002 TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the U.S.) and continues under this process as of December 31, 2009. As a result of these proceedings, TXU Europe Limited may be liquidated or otherwise reorganized in such a way as to relieve it of its obligations under its guarantee.

At December 31, 2009, the Company has a $154.3 million letter of credit for collateral for bank guarantees issued with respect to certain reclamation and performance obligations related to some of the Company s Australian mines.

Other Guarantees

The Company has a liability recorded of $52.3 million as of December 31, 2009 and $61.8 million as of December 31, 2008 related to reclamation and bonding commitments associated with the purchase of approximately 427 million tons of coal reserves and surface lands in the Illinois Basin in 2007.

The Company is the lessee under numerous equipment and property leases. It is common in such commercial lease transactions for the Company, as the lessee, to agree to indemnify the lessor for the value of the property or equipment leased, should the property be damaged or lost during the course of the Company s operations. The Company expects that losses with respect to leased property would be covered by insurance (subject to deductibles). The Company and certain of its subsidiaries have guaranteed other subsidiaries performance under their various lease obligations. Aside from indemnification of the lessor for the value of the property leased, the Company s maximum potential obligations under its leases are equal to the respective future minimum lease payments as presented in Note 9, and the Company assumes that no amounts could be recovered from third parties.

A subsidiary of the Company owns a 5.06% undivided interest in Prairie State, which is currently under construction. In connection with the development of Prairie State, each owner, including the Company s subsidiary, has a guarantee for its proportionate share of obligations to pay its percentage of the construction costs under the Target Price Engineering, Procurement and Construction Agreement with Bechtel Power Corporation. The Company has capitalized development costs of $126.5 million and $69.7 million that were recorded as part of Investments and other assets in the consolidated balance sheets as of December 31, 2009 and 2008, respectively. The Company spent $56.8 million during the year ended December 31, 2009 representing its 5.06% share of the construction costs. Total construction costs for Prairie State are expected to be approximately $4 billion.

The Company has provided financial guarantees under certain long-term debt agreements entered into by its subsidiaries, and substantially all of the Company s subsidiaries provide financial guarantees under long-term debt agreements entered into by the Company. The maximum amounts payable under the Company s debt agreements are equal to the respective principal and interest payments. See Note 12 for the descriptions of the Company s (and its subsidiaries) debt. Supplemental guarantor/non-guarantor financial information is provided in Note 23.

As part of the Patriot spin-off, the Company agreed to maintain in force several letters of credit that secured Patriot obligations for certain employee benefits and workers compensation obligations. As of December 31, 2009, these letters of credit were released as Patriot satisfied the beneficiaries with alternate letters of credit or insurance.

A discussion of the Company s accounts receivable securitization program is included in Note 6 to the consolidated financial statements.

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(20) Commitments and Contingencies

Commitments

As of December 31, 2009, purchase commitments for capital expenditures were $70.4 million. Commitments for expenditures to be made under coal leases are reflected in Note 9. The Company has also various long- and short-term take or pay arrangements associated with rail and port commitments for the delivery of coal, some of which extend to 2040, including amounts relating to export facilities currently under construction which are expected to be completed in 2010. As of December 31, 2009, these commitments totaled $1,864.4 million with $718.5 million obligated within the next five years and $110.7 million obligated within the next year.

From time to time, the Company or its subsidiaries are involved in legal proceedings arising in the ordinary course of business or related to indemnities or historical operations. The Company believes it has recorded adequate reserves for these liabilities and that there is no individual case pending that is likely to have a material adverse effect on the Company s financial condition, results of operations or cash flows. The Company discusses its significant legal proceedings below.

Litigation Relating to Continuing Operations

Navajo Nation Litigation. On June 18, 1999, the Navajo Nation served three of the Company s subsidiaries, including Peabody Western Coal Company (Peabody Western), with a complaint that had been filed in the U.S. District Court for the District of Columbia. The Navajo Nation has alleged 16 claims, including Civil Racketeer Influenced and Corrupt Organizations Act (RICO) violations and fraud. The complaint alleges that the defendants jointly participated in unlawful activity to obtain favorable coal lease amendments. The plaintiff is seeking various remedies including actual damages of at least $600 million, which could be trebled under the RICO counts, punitive damages of at least $1 billion, a determination that Peabody Western s two coal leases have terminated due to Peabody Western s breach of these leases and a reformation of these leases to adjust the royalty rate to 20%. Subsequently, the court allowed the Hopi Tribe to intervene in this lawsuit and the Hopi Tribe is also seeking unspecified actual damages, punitive damages and reformation of its coal lease. One of the Company s subsidiaries named as a defendant is now a subsidiary of Patriot. However, the Company is responsible for this litigation under the Separation Agreement entered into with Patriot in connection with the spin-off. On April 6, 2009, the U.S. Supreme Court ruled against the Navajo Nation in a related case against the U.S. government, and remanded that case to the lower court to dismiss the complaint. The U.S. Supreme Court said that none of the sources relied on by the Navajo Nation provided a basis for its breach-of-trust lawsuit against the U.S. government, which undermines some of the claims the Navajo Nation asserts in its litigation against the Company.

The outcome of this litigation is subject to numerous uncertainties. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes this matter is likely to be resolved without a material adverse effect on the Company s financial condition, results of operations or cash flows.

Gulf Power Company Litigation. On June 22, 2006, Gulf Power Company (Gulf Power) filed a breach of contract lawsuit against a Company subsidiary in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration by the Company s subsidiary under a coal supply agreement with Gulf Power and seeking damages for alleged past and future tonnage shortfalls of nearly 5 million tons under the agreement, which expired on December 31, 2007. In February 2008, the court denied the Company s motion to dismiss the Florida lawsuit or to transfer it to Illinois and retained jurisdiction over the case. Gulf Power filed a motion for partial summary judgment on liability, and the Company subsidiary filed a motion for summary judgment seeking complete dismissal. On September 30, 2009, the court granted Gulf Power s motion for partial summary judgment and denied the Company subsidiary s motion for summary judgment. In October 2009, the Company

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subsidiary filed a motion for reconsideration which the court denied. The damages portion of the trial was held in February 2010; however, the court has not yet rendered its decision in the case.

The outcome of this litigation is subject to numerous uncertainties. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot reasonably be estimated. However, based on current information, the Company believes this matter is likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Claims and Litigation Relating to Indemnities or Historical Operations

Oklahoma Lead Litigation. Gold Fields Mining, LLC (Gold Fields) is a dormant, non-coal producing entity that was previously managed and owned by Hanson PLC, the Company s predecessor owner. In a February 1997 spin-off, Hanson PLC transferred ownership of Gold Fields to the Company, despite the fact that Gold Fields had no ongoing operations and the Company had no prior involvement in its past operations. Gold Fields is currently one of the Company s subsidiaries. The Company indemnified TXU Group with respect to certain claims relating to a former affiliate of Gold Fields. A predecessor of Gold Fields formerly operated two lead mills near Picher, Oklahoma prior to the 1950s and mined, in accordance with lease agreements and permits, approximately 0.15% of the total amount of the crude ore mined in the county.

Gold Fields and several other companies are defendants in two property damage lawsuits arising from past operations near Picher, Oklahoma. The plaintiffs are seeking compensatory damages for diminution in property values and punitive damages. These cases were originally filed as putative class actions, but the court has denied class certification and the cases were subsequently amended to include a number of individual plaintiffs. In December 2003, the Quapaw Indian tribe and certain Quapaw land owners filed a lawsuit against Gold Fields, five other companies and the U.S. The plaintiffs are seeking compensatory and punitive damages based on a variety of theories. In December 2007, the court dismissed the tribe s medical monitoring claim. In July 2008, the court dismissed the tribe s claim for interim and lost use damages under the Comprehensive Environmental Response, Compensation and Liability Act without prejudice to refile at the point the U.S. Environmental Protection Agency (EPA) selects a final remedy for the site. Gold Fields has filed a third-party complaint against the U.S. and other parties. In February 2005, the state of Oklahoma on behalf of itself and several other parties sent a notice to Gold Fields and other companies regarding a possible natural resources damage claim. All of the lawsuits are pending in the U.S. District Court for the Northern District of Oklahoma.

The outcome of litigation and these claims are subject to numerous uncertainties. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes this matter is likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Environmental Claims and Litigation

Environmental claims have been asserted against Gold Fields related to activities of Gold Fields or a former affiliate. Gold Fields or the former affiliate has been named a potentially responsible party (PRP) at five national priority list sites based on the Superfund Amendments and Reauthorization Act of 1986. Claims were asserted at 12 additional sites, bringing the total to 17, which have since been reduced to 11 by completion of work, transfer or regulatory inactivity. The number of PRP sites in and of itself is not a relevant measure of liability, because the nature and extent of environmental concerns varies by site, as does the estimated share of responsibility for Gold Fields or the former affiliate. Undiscounted liabilities for environmental cleanup-related costs for all of the sites noted above were $49.5 million as of December 31, 2009 and $45.3 million as of December 31, 2008, $7.9 million and $7.6 million of which was reflected as a current liability, respectively. These amounts represent those costs that the Company believes are probable and reasonably estimable. In September 2005, Gold Fields and other PRPs received a letter from the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

U.S. Department of Justice alleging that the PRP s mining operations caused the EPA to incur approximately $125 million in residential yard remediation costs at Picher, Oklahoma and will cause the EPA to incur additional remediation costs relating to historical mining sites. In September 2008, Gold Fields and other PRPs received letters from the U.S. Department of Justice and the EPA re-initiating settlement negotiations. Gold Fields continues to participate in the settlement discussions. Gold Fields believes it has meritorious defenses to these claims. Gold Fields is involved in other litigation in the Picher area, and the Company indemnified TXU Group with respect to a defendant as is more fully discussed under the Oklahoma Lead Litigation caption above. Gold Fields has also been contacted by the state of Kansas (Kansas Department of Health and Environment) and is in negotiations for final resolution of natural resource damages claims at two sites. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than the liabilities recorded in the consolidated balance sheets. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes these claims and litigation are likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Comer, et al v. Murphy Oil Co., et al. In April 2006, residents and owners of land and property along the Mississippi Gulf coast filed a purported class action lawsuit in the U.S. District Court in the Southern District of Mississippi against more than 45 oil, chemical, utility and coal companies, including the Company. The plaintiffs alleged that defendants greenhouse gas emissions were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina, and sought damages based on several legal theories. The defendants filed motions to dismiss on the grounds of lack of personal and subject matter jurisdiction. In August 2007, the court granted defendants motion to dismiss for lack of subject matter jurisdiction finding that plaintiffs claims are barred by the political question doctrine and for lack of standing. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed in part the decision of the trial court, holding that the plaintiffs had standing to assert their public and private nuisance, trespass and negligence claims. The Fifth Circuit held that plaintiffs did not satisfy the prudential standing requirement for their unjust enrichment, fraudulent misrepresentation and civil conspiracy claims and dismissed those claims. The case was remanded to the court for further proceedings. The Company believes that this lawsuit is without merit and intends to defend against and oppose it vigorously, but cannot predict its outcome. Based on the Company s evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes this matter is likely to be resolved without a materially adverse effect on its financial condition, results of operations or cash flows.

Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al. In February 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against the Company, several owners of electricity generating facilities and several oil companies. The plaintiffs are the governing bodies of a village in Alaska that they contend is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for nuisance, and allege that the defendants have acted in concert and are jointly and severally liable for the plaintiffs damages. The suit seeks damages for lost property values and for the cost of relocating the village. The defendants filed motions to dismiss on the grounds of lack of personal and subject matter jurisdiction. In September 2009, the court granted defendants motion to dismiss for lack of subject matter jurisdiction finding that plaintiffs federal claim for nuisance is barred by the political question doctrine and for lack of standing. The plaintiffs are appealing the court s dismissal.

Other

In addition, at times the Company becomes a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Company does business. Based on current information, the Company believes that the ultimate resolution of such other pending or threatened proceedings is not reasonably likely to have a material adverse effect on its financial position, results of operations or liquidity.

New York Office of the Attorney General Subpoena. The New York Office of the Attorney General sent a letter to the Company dated September 14, 2007 that referred to the Company s plans to build new coal-fired electric generating units, and said that the increase in CO_2 emissions from the operation of these units, in combination with Peabody Energy s other coal-fired power plants, will subject Peabody Energy to increased financial, regulatory, and litigation risks. The Company currently has no electricity generating capacity in place. The letter included a subpoena issued under New York state law, which seeks information and documents relating to the Company s analysis of the risks associated with climate change and possible climate change legislation or regulations, and its disclosure of such risks to investors. The Company believes that it has made full and proper disclosure of these potential risks.

(21) Summary Quarterly Financial Information (Unaudited)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2009 and 2008 is presented below. In the third quarter of 2009, the Company s Chain Valley Mine in Australia was held for sale and subsequently sold in the fourth quarter of 2009. See Note 2 for additional information regarding the sale. All periods presented below reflect the Chain Valley Mine as a discontinued operation.

	Year Ended December 31, 2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions except per share data)			
Revenues	$ 1,453.0	$ 1,338.2	$ 1,667.0	$ 1,554.2
Operating profit	219.7	215.4	220.3	189.4
Income from continuing operations, net of income taxes	141.2	90.0	113.2	113.5
Net income	175.2	82.0	110.8	95.0
Net income attributable to common stockholders	170.0	79.2	106.8	92.2
Basic earnings per share continuing operations[1]	0.51	0.33	0.41	0.41
Diluted earnings per share continuing operations[1]	0.50	0.32	0.41	0.41
Weighted average shares used in calculating basic earnings per share	265.3	265.4	265.7	265.8
Weighted average shares used in calculating diluted earnings per share	267.3	267.1	267.3	267.7

(1) Earnings per share for the quarters may not add to the amounts for the year as each period is computed on a discrete basis.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating profit in the second, third and fourth quarters reflect lower contract pricing in Australia that began in the second quarter. Operating profit in the fourth quarter included an impairment loss of $34.7 million (see Investments in Joint Ventures section of Note 1 for additional information). Income from continuing operations, net of income taxes in the first quarter included a benefit of $0.9 million from the remeasurement of non-U.S. income tax accounts while the second, third and fourth quarters included non-cash tax expense of $47.7 million, $22.3 million, and $5.3 million, respectively. Net income in the first quarter included a gain of approximately $35 million (net of income taxes) related to a coal excise tax refund (see Note 2 for additional information).

	Year Ended December 31, 2008 (In millions except per share data)			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 1,259.9	$ 1,517.6	$ 1,889.6	$ 1,893.9
Operating profit	185.0	346.0	496.6	368.7
Income from continuing operations, net of income taxes	79.5	244.9	383.2	280.3
Net income	57.9	235.8	371.8	293.6
Net income attributable to common stockholders	57.0	233.3	369.5	293.1
Basic earnings per share continuing operations[1]	0.30	0.89	1.40	1.04
Diluted earnings per share continuing operations[1]	0.29	0.89	1.39	1.04
Weighted average shares used in calculating basic earnings per share	269.2	270.0	270.2	266.1
Weighted average shares used in calculating diluted earnings per share	271.5	271.9	271.8	267.2

(1) Earnings per share for the quarters may not add to the amounts for the year as each period is computed on a discrete basis.

Operating profit in the first quarter included a $54.0 million gain on the sale of coal reserves and surface lands (see Note 4 for information). The second, third and fourth quarter operating profits reflect higher contract pricing in Australia that began in the second quarter. The second quarter operating profit also included revenue recovery of $56.9 million on coal supply agreements. Income from continuing operations, net of income taxes for the first and second quarters included non-cash tax expense of $15.8 million and $17.6 million, respectively, from the remeasurement of non-U.S. income tax accounts while the third and fourth quarters included non-cash tax benefits of $62.7 million and $35.9, respectively. Income from continuing operations, net of income taxes in the second quarter also included a tax benefit of $45.3 million due to the reduction in net operating loss valuation allowances (see Note 11 for information). Net income in the first quarter included a loss of approximately $12 million (net of income taxes) related to a coal excise tax refund (see Note 2 for additional information).

(22) Segment Information

The Company reports its operations primarily through the following reportable operating segments: Western U.S. Mining, Midwestern U.S. Mining, Australian Mining, Trading and Brokerage and Corporate and Other. Wes U.S. Mining operations reflect the aggregation of the Powder River Basin, Southwest and Colorado mining operations, and Midwestern U.S. Mining operations reflects the Company s Illinois and Indiana mining operations. In 2008, the Company renamed its Eastern U.S. Mining segment to Midwestern U.S. Mining segment to better reflect the geography of the continuing operations of that region.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The principal business of the Western U.S. Mining, Midwestern U.S. Mining and Australian Mining segments is the mining, preparation and sale of thermal coal, sold primarily to electric utilities, and metallurgical coal, sold to steel and coke producers. For the year ended December 31, 2009, 81% of the Company s total sales (by volume) were to U.S. electricity generators, 17% were to customers outside the U.S. and 2% were to the U.S. industrial sector. Western U.S. Mining operations are characterized by predominantly surface mining extraction processes, lower sulfur content and Btu of coal and higher customer transportation costs (due to longer shipping distances). Conversely, Midwestern U.S. Mining operations are characterized by a mix of surface and underground mining extraction processes, higher sulfur content and Btu of coal and lower customer transportation costs (due to shorter shipping distances). Geologically, Western operations mine bituminous and subbituminous coal deposits, and Midwestern operations mine bituminous coal deposits. Australian Mining operations are characterized by both surface and underground extraction processes, mining various qualities of low-sulfur, high Btu coal (metallurgical coal) as well as thermal coal primarily sold to an international customer base with a small portion sold to Australian steel producers and power generators. The Trading and Brokerage segment s principal business is the brokering of coal sales of other coal producers both as principal and agent, and the trading of coal, freight and freight-related contracts. Corporate and Other includes selling and administrative expenses, net gains on property disposals, costs associated with past mining obligations, joint venture earnings (losses) and revenues and expenses related to the Company s other commercial activities such as generation development, Btu Conversion, clean coal technologies and resource management.

The Company s chief operating decision maker uses Adjusted EBITDA as the primary measure of segment profit and loss. The Company defines Adjusted EBITDA as income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expense and depreciation, depletion and amortization.

Operating segment results for the year ended December 31, 2009 were as follows:

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
			(Dollars in millions)			
Revenues	$ 2,612.6	$ 1,303.8	$ 1,678.0	$ 391.0	$ 27.0	$ 6,012.4
Adjusted EBITDA	721.5	281.9	437.8	193.4	(344.5)	1,290.1
Total assets	3,061.3	334.3	3,386.8	673.0	2,499.9	9,955.3
Additions to property, plant, equipment and mine development	78.3	104.2	70.1	1.8	6.2	260.6
Federal coal lease expenditures	123.6					123.6
Income (loss) from equity affiliates					(69.1)	(69.1)
Additions to advance mining royalties	1.5	1.6			3.0	6.1

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating segment results for the year ended December 31, 2008 were as follows:

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in millions)					
Revenues	$ 2,533.1	$ 1,154.6	$ 2,242.8	$ 601.8	$ 28.7	$ 6,561.0
Adjusted EBITDA	681.3	177.3	1,016.6	218.9	(247.2)	1,846.9
Total assets	3,140.4	552.0	2,985.9	920.3	2,097.0	9,695.6
Additions to property, plant, equipment and mine development	140.4	30.3	62.8		30.6	264.1
Federal coal lease expenditures	178.5					178.5
Income (loss) from equity affiliates						
Additions to advance mining royalties	2.1	2.2			1.7	6.0

Operating segment results for the year ended December 31, 2007 were as follows:

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in millions)					
Revenues	$ 2,063.2	$ 987.1	$ 1,117.6	$ 320.7	$ 35.2	$ 4,523.8
Adjusted EBITDA	595.4	200.0	167.2	116.6	(109.5)	969.7
Total assets	2,893.8	529.6	3,033.3	346.8	2,278.8	9,082.3
Additions to property, plant, equipment and mine development	175.4	34.0	167.2		62.2	438.8
Federal coal lease expenditures	178.2					178.2
Income (loss) from equity affiliates					14.5	14.5
Additions to advance mining royalties	1.5	2.7			3.9	8.1

A reconciliation of adjusted EBITDA to consolidated income from continuing operations follows:

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Total adjusted EBITDA	$ 1,290.1	$ 1,846.9	$ 969.7
Depreciation, depletion and amortization	(405.2)	(402.4)	(346.3)
Asset retirement obligation expense	(40.1)	(48.2)	(23.7)
Interest expense	(201.2)	(227.0)	(235.8)
Interest income	8.1	10.0	7.0
Income tax (provision) benefit	(193.8)	(191.4)	70.7
Income from continuing operations, net of income taxes	$ 457.9	$ 987.9	$ 441.6

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(23) Supplemental Guarantor/Non-Guarantor Financial Information

In accordance with the indentures governing the 6.875% Senior Notes due March 2013, the 5.875% Senior Notes due March 2016, the 7.375% Senior Notes due November 2016 and the 7.875% Senior Notes due November 2026, certain wholly-owned U.S. subsidiaries of the Company have fully and unconditionally guaranteed these Senior Notes, on a joint and several basis. Separate financial statements and other disclosures concerning the Guarantor Subsidiaries are not presented because management believes that such information is not material to the Senior Note holders. The following historical financial statement information is provided for the Guarantor/Non-Guarantor Subsidiaries.

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SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2009				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$	$ 4,024.0	$ 2,312.5	$ (324.1)	$ 6,012.4
Costs and expenses					
Operating costs and expenses	104.4	2,958.5	1,728.9	(324.1)	4,467.7
Depreciation, depletion and amortization		287.6	117.6		405.2
Asset retirement obligation expense		33.3	6.8		40.1
Selling and administrative expenses	29.3	168.9	10.5		208.7
Other operating (income) loss:					
Net gain on disposal or exchange of assets		(17.1)	(6.1)		(23.2)
(Income) loss from equity affiliates	(620.9)	6.3	62.8	620.9	69.1
Interest expense	198.4	52.6	16.2	(66.0)	201.2
Interest income	(15.3)	(28.9)	(29.9)	66.0	(8.1)
Income from continuing operations before income taxes	304.1	562.8	405.7	(620.9)	651.7
Income tax provision (benefit)	(122.3)	184.1	132.0		193.8
Income from continuing operations, net of income taxes	426.4	378.7	273.7	(620.9)	457.9
Income (loss) from discontinued operations, net of income taxes	21.8	(2.7)	(14.0)		5.1
Net income	448.2	376.0	259.7	(620.9)	463.0
Less: Net income attributable to noncontrolling interests			14.8		14.8
Net income attributable to common stockholders	$ 448.2	$ 376.0	$ 244.9	$ (620.9)	$ 448.2

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PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2008				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$	$ 3,788.4	$ 2,981.4	$ (208.8)	$ 6,561.0
Costs and expenses					
Operating costs and expenses	(51.5)	3,034.7	1,810.8	(208.8)	4,585.2
Depreciation, depletion and amortization		265.9	136.5		402.4
Asset retirement obligation expense		42.8	5.4		48.2
Selling and administrative expenses	22.0	171.6	8.2		201.8
Other operating (income) loss:					
Net gain on disposal or exchange of assets		(72.7)	(0.2)		(72.9)
(Income) loss from equity affiliates	(1,075.0)	5.7	(5.7)	1,075.0	
Interest expense	220.5	22.4	42.0	(57.9)	227.0
Interest income	(15.1)	(24.2)	(28.6)	57.9	(10.0)
Income from continuing operations before income taxes	899.1	342.2	1,013.0	(1,075.0)	1,179.3
Income tax provision (benefit)	(67.7)	101.3	157.8		191.4
Income from continuing operations, net of income taxes	966.8	240.9	855.2	(1,075.0)	987.9
Income (loss) from discontinued operations, net of income taxes	(13.9)	(27.9)	13.0		(28.8)
Net income	952.9	213.0	868.2	(1,075.0)	959.1
Less: Net income (loss) attributable to noncontrolling interests		(0.1)	6.3		6.2
Net income attributable to common stockholders	$ 952.9	$ 213.1	$ 861.9	$ (1,075.0)	$ 952.9

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	Year Ended December 31, 2007				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$	$ 3,271.7	$ 1,414.0	$ (161.9)	$ 4,523.8
Costs and expenses					
Operating costs and expenses	(72.2)	2,533.6	1,210.6	(161.9)	3,510.1
Depreciation, depletion and amortization		236.0	110.3		346.3
Asset retirement obligation expense		17.8	5.9		23.7
Selling and administrative expenses	21.5	121.4	4.2		147.1
Other operating (income) loss:					
Net (gain) loss on disposal or exchange of assets		(88.8)	0.2		(88.6)
(Income) loss from equity affiliates	(536.6)	6.7	(21.2)	536.6	(14.5)
Interest expense	279.5	32.1	26.6	(102.4)	235.8
Interest income	(17.5)	(68.0)	(23.9)	102.4	(7.0)
Income (loss) from continuing operations before income taxes	325.3	480.9	101.3	(536.6)	370.9
Income tax provision (benefit)	(83.8)	(94.4)	107.5		(70.7)
Income (loss) from continuing operations, net of income taxes	409.1	575.3	(6.2)	(536.6)	441.6
Loss from discontinued operations, net of income taxes	(145.3)	(8.2)	(26.6)		(180.1)
Net income (loss)	263.8	567.1	(32.8)	(536.6)	261.5
Less: Net income (loss) attributable to noncontrolling interests		0.9	(3.2)		(2.3)
Net income (loss) attributable to common stockholders	$ 263.8	$ 566.2	$ (29.6)	$ (536.6)	$ 263.8

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2009				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Reclassifications/ Eliminations	Consolidated
	(Dollars in millions)				
Assets					
Current assets					
Cash and cash equivalents	$ 368.4	$ 0.2	$ 620.2	$	$ 988.8
Accounts receivable, net	0.6	55.5	246.9		303.0
Inventories		152.5	172.6		325.1
Assets from coal trading activities, net		92.8	184.0		276.8
Deferred income taxes	11.6	56.5		(28.1)	40.0
Other current assets	133.9	30.7	90.7		255.3
Total current assets	514.5	388.2	1,314.4	(28.1)	2,189.0
Property, plant, equipment and mine development					
Land and coal interests		4,807.3	2,750.0		7,557.3
Buildings and improvements		783.4	124.6		908.0
Machinery and equipment		1,117.3	273.9		1,391.2
Less: accumulated depreciation, depletion and amortization		(2,096.6)	(498.4)		(2,595.0)
Property, plant, equipment and mine development, net		4,611.4	2,650.1		7,261.5
Deferred income taxes	124.0			(124.0)	
Investments and other assets	8,893.5	110.5	32.0	(8,531.2)	504.8
Total assets	$ 9,532.0	$ 5,110.1	$ 3,996.5	$ (8,683.3)	$ 9,955.3
Liabilities and Stockholders Equity					
Current liabilities					
Current maturities of long-term debt	$	$	$ 14.1	$	$ 14.1
Payables to (receivables from) affiliates, net	1,937.2	(1,975.9)	38.7		
Liabilities from coal trading activities, net		45.1	65.5		110.6
Deferred income taxes			28.1	(28.1)	
Accounts payable and accrued expenses	106.6	661.7	419.4		1,187.7
Total current liabilities	2,043.8	(1,269.1)	565.8	(28.1)	1,312.4
Long-term debt, less current maturities	2,635.4	0.1	102.7		2,738.2

Deferred income taxes		173.3	249.8	(124.0)	299.1
Notes payable to (receivables from) affiliates, net	1,032.5	(1,035.0)	2.5		
Other noncurrent liabilities	70.6	1,667.8	111.3		1,849.7
Total liabilities	5,782.3	(462.9)	1,032.1	(152.1)	6,199.4
Peabody Energy Corporation s stockholders equity	3,749.7	5,573.0	2,958.2	(8,531.2)	3,749.7
Noncontrolling interests			6.2		6.2
Total stockholders equity	3,749.7	5,573.0	2,964.4	(8,531.2)	3,755.9
Total liabilities and stockholders equity	$ 9,532.0	$ 5,110.1	$ 3,996.5	$ (8,683.3)	$ 9,955.3

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PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2008				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Reclassifications/ Eliminations	Consolidated
	(Dollars in millions)				
Assets					
Current assets					
Cash and cash equivalents	$ 161.2	$ 4.5	$ 284.0	$	$ 449.7
Accounts receivable, net	0.6	4.8	376.8		382.2
Inventories		173.7	102.5		276.2
Assets from coal trading activities, net		226.2	436.6		662.8
Deferred income taxes	43.7	21.7		(63.7)	1.7
Other current assets	51.0	77.8	69.9		198.7
Total current assets	256.5	508.7	1,269.8	(63.7)	1,971.3
Property, plant, equipment and mine development					
Land and coal interests		4,655.5	2,693.9		7,349.4
Buildings and improvements		748.6	109.5		858.1
Machinery and equipment		1,016.1	229.0		1,245.1
Less: accumulated depreciation, depletion and amortization		(1,806.7)	(348.6)		(2,155.3)
Property, plant, equipment and mine development, net		4,613.5	2,683.8		7,297.3
Deferred income taxes	191.3			(191.3)	
Investments and other assets	8,439.1	375.2	25.9	(8,413.2)	427.0
Total assets	$ 8,886.9	$ 5,497.4	$ 3,979.5	$ (8,668.2)	$ 9,695.6
Liabilities and Stockholders Equity					
Current liabilities					
Current maturities of long-term debt	$	$	$ 17.0	$	$ 17.0
Payables to (receivables from) affiliates, net	1,610.5	(1,632.7)	22.2		
Liabilities from coal trading activities, net		109.3	194.9		304.2
Deferred income taxes			63.7	(63.7)	
Accounts payable and accrued expenses	376.7	725.9	432.4		1,535.0

Total current liabilities	1,987.2	(797.5)	730.2	(63.7)	1,856.2
Long-term debt, less current maturities	2,640.4	0.2	136.0		2,776.6
Deferred income taxes		20.1	192.0	(191.3)	20.8
Notes payable to (receivables from) affiliates, net	819.2	(819.2)			
Other noncurrent liabilities	322.0	1,517.2	83.3		1,922.5
Total liabilities	5,768.8	(79.2)	1,141.5	(255.0)	6,576.1
Peabody Energy Corporation s stockholders equity	3,118.1	5,576.6	2,836.6	(8,413.2)	3,118.1
Noncontrolling interests			1.4		1.4
Total stockholders equity	3,118.1	5,576.6	2,838.0	(8,413.2)	3,119.5
Total liabilities and stockholders equity	$ 8,886.9	$ 5,497.4	$ 3,979.5	$ (8,668.2)	$ 9,695.6

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PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2009			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in millions)			
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$ (215.9)	$ 792.7	$ 476.7	$ 1,053.5
Net cash provided by (used in) discontinued operations	7.4	(5.3)	(7.7)	(5.6)
Net cash provided by (used in) operating activities	(208.5)	787.4	469.0	1,047.9
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development		(189.7)	(70.9)	(260.6)
Investment in Prairie State Energy Campus		(56.8)		(56.8)
Federal coal lease expenditures		(123.6)		(123.6)
Proceeds from disposal of assets, net of notes receivable		43.8	10.1	53.9
Additions to advance mining royalties		(5.8)	(0.3)	(6.1)
Investment in equity affiliates and joint ventures		(5.0)	(10.0)	(15.0)
Net cash used in continuing operations		(337.1)	(71.1)	(408.2)
Net cash provided by discontinued operations			1.7	1.7
Net cash used in investing activities		(337.1)	(69.4)	(406.5)
Cash Flows From Financing Activities				
Payments of long-term debt			(37.1)	(37.1)
Dividends paid	(66.8)			(66.8)
Proceeds from stock options exercised	3.6			3.6
Net proceeds from borrowings			0.8	0.8
Other, net	5.1		(7.9)	(2.8)
Transactions with affiliates, net	473.9	(454.6)	(19.3)	
Net cash provided by (used in) financing activities	415.8	(454.6)	(63.5)	(102.3)
Net change in cash and cash equivalents	207.3	(4.3)	336.1	539.1
Cash and cash equivalents at beginning of year	161.2	4.5	284.0	449.7

Cash and cash equivalents at end of year	$ 368.5	$ 0.2	$ 620.1	$ 988.8

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PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in millions)			
Cash Flows From Operating Activities				
Net cash provided by continuing operations	$ 17.7	$ 465.6	$ 926.5	$ 1,409.8
Net cash used in discontinued operations	(94.5)	(17.3)	(11.2)	(123.0)
Net cash provided by (used in) operating activities	(76.8)	448.3	915.3	1,286.8
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development		(198.0)	(66.1)	(264.1)
Investment in Prairie State Energy Campus		(40.9)		(40.9)
Federal coal lease expenditures		(178.5)		(178.5)
Proceeds from disposal of assets, net of notes receivable		72.3	0.5	72.8
Additions to advance mining royalties		(5.7)	(0.3)	(6.0)
Investments in equity affiliates and joint ventures		(2.6)		(2.6)
Net cash used in continuing operations		(353.4)	(65.9)	(419.3)
Net cash provided by (used in) discontinued operations		(0.4)	24.3	23.9
Net cash used in investing activities		(353.8)	(41.6)	(395.4)
Cash Flows From Financing Activities				
Change in revolving line of credit	(97.7)			(97.7)
Payments of long-term debt	(18.8)		(13.9)	(32.7)
Common stock repurchase	(199.8)			(199.8)
Dividends paid	(64.9)			(64.9)
Proceeds from stock options exercised	14.1			14.1
Acquisition of noncontrolling interests (Millennium Mine)			(110.1)	(110.1)
Other, net	5.2		(1.1)	4.1
Transactions with affiliates, net	592.9	(93.9)	(499.0)	
Net cash provided by (used in) financing activities	231.0	(93.9)	(624.1)	(487.0)
Net change in cash and cash equivalents	154.2	0.6	249.6	404.4

Cash and cash equivalents at beginning of year		7.0		3.9		34.4		45.3
Cash and cash equivalents at end of year	$	161.2	$	4.5	$	284.0	$	449.7

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in millions)			
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$ 1.6	$ 686.9	$ (227.8)	$ 460.7
Net cash used in discontinued operations	(25.5)	(7.1)	(108.7)	(141.3)
Net cash provided by (used in) operating activities	(23.9)	679.8	(336.5)	319.4
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	(25.0)	(244.3)	(169.5)	(438.8)
Investment in Prairie State Energy Campus		(28.8)		(28.8)
Federal coal lease expenditures		(178.2)		(178.2)
Proceeds from disposal of assets, net of notes receivable		118.3	1.3	119.6
Additions to advance mining royalties		(8.1)		(8.1)
Investments in equity affiliates and joint ventures		(4.6)		(4.6)
Net cash used in continuing operations	(25.0)	(345.7)	(168.2)	(538.9)
Net cash used in discontinued operations		(1.8)	(34.6)	(36.4)
Net cash used in investing activities	(25.0)	(347.5)	(202.8)	(575.3)
Cash Flows From Financing Activities				
Change in revolving line of credit	97.7			97.7
Payments of long-term debt	(51.1)	(60.9)	(5.8)	(117.8)
Dividends paid	(63.7)			(63.7)
Payment of debt issuance costs		(0.8)		(0.8)
Excess tax benefit related to stock options exercised	96.7			96.7
Proceeds from stock options exercised	26.2			26.2
Other, net	6.4		(3.0)	3.4
Transactions with affiliates, net	(261.5)	(270.4)	531.9	
Net cash provided by (used in) continuing operations	(149.3)	(332.1)	523.1	41.7
Net cash used in discontinued operations	(67.0)			(67.0)

Net cash provided by (used in) financing activities	(216.3)	(332.1)	523.1	(25.3)
Net change in cash and cash equivalents	(265.2)	0.2	(16.2)	(281.2)
Cash and cash equivalents at beginning of year	272.2	3.7	50.6	326.5
Cash and cash equivalents at end of year	$ 7.0	$ 3.9	$ 34.4	$ 45.3

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the consolidated financial statements of Peabody Energy Corporation (the Company) as of December 31, 2009 and 2008, and for each of the three years in the period ended December 31, 2009, and have issued our report thereon dated February 24, 2010. Our audits also included the financial statement schedule listed in Item 15(a). This schedule is the responsibility of the Company s management. Our responsibility is to express an opinion based on our audits.

In our opinion, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 24, 2010

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Schedule Of Valuation And Qualifying Accounts Disclosure

PEABODY ENERGY CORPORATION

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[1]	Other	Balance at End of Period
		(Dollars in millions)			
Year ended December 31, 2009					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 17.2	$ 1.6	$ (2.2)	$ 0.6[2]	$ 17.2
Reserve for materials and supplies	4.9	3.6	(2.3)		6.2
Allowance for doubtful accounts	24.8	7.7	(3.6)	(10.6)[3]	18.3
Year ended December 31, 2008					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 13.6	$ 4.0	$ (3.0)	$ 2.6[2]	$ 17.2
Reserve for materials and supplies	4.3	1.7	(1.1)		4.9
Allowance for doubtful accounts	11.9	13.9	(1.0)		24.8
Year ended December 31, 2007					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 12.0	$	$	$ 1.6[2]	$ 13.6
Reserve for materials and supplies	3.2	0.5	(0.7)	1.3[2]	4.3
Allowance for doubtful accounts	10.9	1.1	(0.1)		11.9

(1) Reserves utilized, unless otherwise indicated.

(2) Balances transferred (to) from other accounts or reserves recorded as part of a property transaction or acquisition.

(3) Reflects subsequent recovery of amounts previously reserved.

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EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K.

Exhibit No.	Description of Exhibit
2 .1	Merger Implementation Agreement, dated as of July 6, 2006, between the Registrant and Excel Coal Limited (Incorporated by reference to Exhibit 2.1 of the Registrant s Current Report on Form 8-K, filed July 7, 2006).
2 .2	Deed of Variation Merger Implementation Agreement, dated as of September 18, 2006, between the Registrant and Excel Coal Limited (Incorporated by reference to Exhibit 2.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
3 .1	Third Amended and Restated Certificate of Incorporation of the Registrant, as amended (Incorporated by reference to Exhibit 3.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
3 .2	Amended and Restated By-Laws of the Registrant (Incorporated by reference to Exhibit 3.1 of the Registrant s Current Report on Form 8-K, filed September 16, 2008).
4 .1	Rights Agreement, dated as of July 24, 2002, between the Registrant and EquiServe Trust Company, N.A., as Rights Agent (which includes the form of Certificate of Designations of Series A Junior Preferred Stock of the Registrant as Exhibit A, the form of Right Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Shares as Exhibit C) (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Registration Statement on Form 8-A, filed July 24, 2002).
4 .2	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant, filed with the Secretary of State of the State of Delaware on July 24, 2002 (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Registration Statement on Form 8-A, filed July 24, 2002).
4 .3	Certificate of Adjustment delivered by the Registrant to Equiserve Trust Company, N.A., as Rights Agent, on March 29, 2005 (Incorporated by reference to Exhibit 4.2 to Amendment No. 1 to the Registrant s Registration Statement on Form 8-A/A, filed March 29, 2005).
4 .4	Certificate of Adjustment delivered by the Registrant to American Stock Transfer & Trust Company, as Rights Agent, on February 22, 2006 (Incorporated by reference to Exhibit 4.2 to Amendment No. 2 to the Registrant s Registration Statement on Form 8-A/A, filed February 22, 2006).
4 .5	Specimen of stock certificate representing the Registrant s common stock, $.01 par value (Incorporated by reference to Exhibit 4.13 to Amendment No. 4 to the Registrant s Form S-1 Registration Statement No. 333-55412, filed May 1, 2001).
4 .6	67/8% Senior Notes Due 2013 Indenture, dated as of March 21, 2003, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.27 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003).
4 .7	67/8% Senior Notes Due 2013 First Supplemental Indenture, dated as of May 7, 2003, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Form S-4 Registration Statement No. 333-106208, filed June 17, 2006).
4 .8	67/8% Senior Notes Due 2013 Second Supplemental Indenture, dated as of September 30, 2003, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.198 of the Registrant s Form S-3 Registration Statement No. 333-109906, filed October 22, 2003).
4 .9	67/8% Senior Notes Due 2013 Third Supplemental Indenture, dated as of February 24, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.211 to Amendment No. 1 to the

	Registrant s Form S-3 Registration Statement No. 333-109906, filed March 4, 2004).
4 .10	67/8% Senior Notes Due 2013 Fourth Supplemental Indenture, dated as of April 22, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 10.57 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).

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Exhibit No.	Description of Exhibit
4 .11	67/8% Senior Notes Due 2013 Fifth Supplemental Indenture, dated as of October 18, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.9 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004).
4 .12	67/8% Senior Notes Due 2013 Sixth Supplemental Indenture, dated as of January 20, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4 .13	67/8% Senior Notes Due 2013 Seventh Supplemental Indenture, dated as of September 30, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005).
4 .14	67/8% Senior Notes Due 2013 Eighth Supplemental Indenture, dated as of January 20, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.14 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2005).
4 .15	67/8% Senior Notes Due 2013 Ninth Supplemental Indenture, dated as of June 13, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
4 .16	67/8% Senior Notes Due 2013 Tenth Supplemental Indenture, dated as of June 30, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
4 .17	67/8% Senior Notes Due 2013 Eleventh Supplemental Indenture, dated as of September 29, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4 .18	67/8% Senior Notes Due 2013 Twelfth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .19	67/8% Senior Notes Due 2013 Thirteenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.19 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .20	67/8% Senior Notes Due 2013 Fourteenth Supplemental Indenture, dated as of June 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
4 .21	67/8% Senior Notes Due 2013 Fifteenth Supplemental Indenture, dated as of November 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
4 .22	

	67/8% Senior Notes Due 2013 Eighteenth Supplemental Indenture, dated as of March 13, 2009, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
4 .23	57/8% Senior Notes Due 2016 Indenture, dated as of March 19, 2004, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4 .24	57/8% Senior Notes Due 2016 First Supplemental Indenture, dated as of March 23, 2004, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K, filed March 25, 2004).

Exhibit No.	Description of Exhibit
4 .25	57/8% Senior Notes Due 2016 Second Supplemental Indenture, dated as of April 22, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 10.58 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4 .26	57/8% Senior Notes Due 2016 Third Supplemental Indenture, dated as of October 18, 2004, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.13 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004).
4 .27	57/8% Senior Notes Due 2016 Fourth Supplemental Indenture, dated as of January 20, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4 .28	57/8% Senior Notes Due 2016 Fifth Supplemental Indenture, dated as of September 30, 2005, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005).
4 .29	57/8% Senior Notes Due 2016 Sixth Supplemental Indenture, dated as of January 20, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2005).
4 .30	57/8% Senior Notes Due 2016 Seventh Supplemental Indenture, dated as of June 13, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
4 .31	57/8% Senior Notes Due 2016 Eighth Supplemental Indenture, dated as of June 30, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
4 .32	57/8% Senior Notes Due 2016 Ninth Supplemental Indenture, dated as of September 29, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4 .33	57/8% Senior Notes Due 2016 Twelfth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.30 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .34	57/8% Senior Notes Due 2016 Fifteenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.31 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .35	57/8% Senior Notes Due 2016 Eighteenth Supplemental Indenture, dated as of June 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
4 .36	57/8% Senior Notes Due 2016 Twenty-First Supplemental Indenture, dated as of November 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National

	Association, as trustee (Incorporated by reference to Exhibit 4.35 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
4 .37	57/8% Senior Notes Due 2016 Thirtieth Supplemental Indenture, dated as of March 13, 2009, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).

Exhibit No.	Description of Exhibit
4 .38	73/8% Senior Notes Due 2016 Tenth Supplemental Indenture, dated as of October 12, 2006 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K, filed October 13, 2006).
4 .39	73/8% Senior Notes Due 2016 Thirteenth Supplemental Indenture, dated as of November 10, 2006 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.33 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .40	73/8% Senior Notes Due 2016 Sixteenth Supplemental Indenture, dated as of January 31, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .41	73/8% Senior Notes Due 2016 Nineteenth Supplemental Indenture, dated as of June 14, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
4 .42	73/8% Senior Notes Due 2016 Thirty-First Supplemental Indenture, dated as of March 13, 2009, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
4 .43	73/8% Senior Notes Due 2016 Twenty-Second Supplemental Indenture, dated as of November 14, 2007 among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.40 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
4 .44	77/8% Senior Notes Due 2026 Eleventh Supplemental Indenture, dated as of October 12, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Current Report on Form 8-K, filed October 13, 2006).
4 .45	77/8% Senior Notes Due 2026 Fourteenth Supplemental Indenture, dated as of November 10, 2006, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.36 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .46	77/8% Senior Notes Due 2026 Seventeenth Supplemental Indenture, dated as of January 31, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.37 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2006).
4 .47	77/8% Senior Notes Due 2026 Twentieth Supplemental Indenture, dated as of June 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
4 .48	77/8% Senior Notes Due 2026 Twenty-Third Supplemental Indenture, dated as of November 14, 2007, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.45 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
4 .49	77/8% Senior Notes Due 2026 Thirty-Second Supplemental Indenture, dated as of March 13, 2009, among the Registrant, the Guaranteeing Subsidiaries (as defined therein), and U.S. Bank National

	Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
4 .50	Subordinated Indenture, dated as of December 20, 2006, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
4 .51	4.75% Convertible Junior Subordinated Debentures Due 2066 First Supplemental Indenture, dated as December 20, 2006, among the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).

Exhibit No.	Description of Exhibit
4 .52	Capital Replacement Covenant dated December 19, 2006 (Incorporated by reference to Exhibit 99.1 of the Registrant s Current Report on Form 8-K, filed December 20, 2006).
4 .53	Notice of Adjustment of Conversion Rate of 4.75% Convertible Junior Subordinated Debentures Due 2066, dated November 26, 2007 (Incorporated by reference to Exhibit 4.49 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
4 .54	Notice of Adjustment of Conversion Rate of 4.75% Convertible Junior Subordinated Debentures Due 2066, dated February 8, 2009 (Incorporated by reference to Exhibit 4.5 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10 .1	Third Amended and Restated Credit Agreement, dated as of September 15, 2006, among the Registrant, Bank of America, N.A., as administrative agent, Citibank, N.A., as syndication agent, and the lenders named therein (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed September 18, 2006).
10 .2	Amendment No. 1 to Third Amended and Restated Credit Agreement, dated as of September 27, 2006, among the Registrant, the Lenders named therein, and Bank of America, N.A., as Administrative Agent (Incorporated by reference to Exhibit 10.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
10 .3	Amended and Restated Guarantee, dated as of September 15, 2006, among the Registrant and the Guarantors (as defined therein) in favor of Bank of America, N.A., as administrative agent under the Third Amended and Restated Credit Agreement dated as of September 15, 2006 (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed September 18, 2006).
10 .4	Federal Coal Lease WYW0321779: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.3 of the Registrant s Form S-4 Registration Statement No. 333-59073).
10 .5	Federal Coal Lease WYW119554: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.4 of the Registrant s Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10 .6	Federal Coal Lease WYW5036: Rawhide Mine (Incorporated by reference to Exhibit 10.5 of the Registrant s Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10 .7	Federal Coal Lease WYW3397: Caballo Mine (Incorporated by reference to Exhibit 10.6 of the Registrant s Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10 .8	Federal Coal Lease WYW83394: Caballo Mine (Incorporated by reference to Exhibit 10.7 of the Registrant s Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10 .9	Federal Coal Lease WYW136142 (Incorporated by reference to Exhibit 10.8 of Amendment No. 1 to the Registrant s Form S-4 Registration Statement No. 333-59073, filed September 8, 1998).
10 .10	Royalty Prepayment Agreement by and among Peabody Natural Resources Company, Gallo Finance Company and Chaco Energy Company, dated September 30, 1998 (Incorporated by reference to Exhibit 10.9 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
10 .11	Federal Coal Lease WYW154001: North Antelope Rochelle South (Incorporated by reference to Exhibit 10.68 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).
10 .12	Federal Coal Lease WYW150210: North Antelope Rochelle Mine (Incorporated by reference to Exhibit 10.8 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
10 .13	Federal Coal Lease WYW151134 effective May 1, 2005: West Roundup (Incorporated by reference to Exhibit 10.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10 .14	Separation Agreement, Plan of Reorganization and Distribution, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed October 25, 2007).

10 .15	Tax Separation Agreement, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed October 25, 2007).

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Exhibit No.	Description of Exhibit
10 .16	Coal Act Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed October 25, 2007).
10 .17	NBCWA Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed October 25, 2007).
10 .18	Salaried Employee Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.5 of the Registrant s Current Report on Form 8-K, filed October 25, 2007).
10 .19	Coal Supply Agreement, dated October 22, 2007, between Patriot Coal Sales LLC and COALSALES II, LLC (Incorporated by reference to Exhibit 10.6 of the Registrant s Current Report on Form 8-K, filed October 25, 2007).
10 .20*	1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 4.9 of the Registrant s Form S-8 Registration Statement No. 333-105456, filed May 21, 2003).
10 .21*	Amendment to the 1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed October 17, 2007).
10 .22*	Amendment No. 2 to the 1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed December 11, 2007).
10 .23*	Form of Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.15 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .24*	Form of Amendment to Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.16 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .25*	Form of Amendment, dated as of June 15, 2004, to Non-Qualified Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.65 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10 .26*	Form of Incentive Stock Option Agreement under the Registrant s 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.17 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .27*	Long-Term Equity Incentive Plan of the Registrant (Incorporated by reference to Exhibit 99.2 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed May 22, 2001).
10 .28*	Amendment to the Registrant s 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed October 17, 2007).
10 .29*	The Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Annex A to the Registrant s Proxy Statement for the 2004 Annual Meeting of Stockholders, filed April 2, 2004).
10 .30*	Amendment No. 1 to the Registrant s 2004 Long Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.67 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).
10 .31*	Amendment No. 2 to the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed October 17, 2007).
10 .32*	

Amendment No. 3 to the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed October 17, 2007).

Exhibit No.	Description of Exhibit
10 .33*	Amendment No. 4 to the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed December 11, 2007).
10 .34*	Form of Non-Qualified Stock Option Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K, filed January 7, 2005).
10 .35*	Form of Performance Units Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed January 7, 2005).
10 .36*	Form of Performance Units Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan. (Incorporated by reference to Exhibit 10.36 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
10 .37*	Equity Incentive Plan for Non-Employee Directors of the Registrant (Incorporated by reference to Exhibit 99.3 of the Registrant s Form S-8 Registration Statement No. 333-61406, filed May 22, 2001).
10 .38*	Form of Non-Qualified Stock Option Agreement for Outside Directors under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K, filed December 14, 2005).
10 .39*	Form of Non-Qualified Stock Option Agreement under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.18 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .40*	Form of Performance Unit Award Agreement under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.19 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .41*	Form of Non-Qualified Stock Option Agreement under the Registrant s Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.20 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .42*	Form of Restricted Stock Agreement under the Registrant s Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.21 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2003).
10 .43*	Form of Restricted Stock Award Agreement for Outside Directors under the Registrant s Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K, filed December 14, 2005).
10 .44*	Form of Performance Unit Award Agreement under the Registrant s 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).
10 .45*	2009 Amendment entered into effective December 31, 2009 to the Stock Grant Agreement dated as of October 1, 2003 between the Registrant and Gregory H. Boyce.
10 .46*	2009 Amendment entered into effective December 31, 2009 to the Non-Qualified Stock Option Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce.
10 .47*	2009 Amendment entered into effective December 31, 2009 to the Non-Qualified Stock Option Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce.
10 .48*	2009 Amendment entered into effective December 31, 2009 to the Performance Units Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce.
10 .49*	2009 Amendment entered into effective December 31, 2009 to the Performance Units Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce.
10 .50*	Amended and Restated Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.44 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2008).

10 .51*	Amendment to the Amended and Restated Employee Stock Purchase Plan of the Registrant.
10 .52*	Amended and Restated Australian Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.45 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2008).

Exhibit No.	Description of Exhibit
10 .53*	Amendment to the Amended and Restated Australian Employee Stock Purchase Plan of the Registrant.
10 .54*	Management Annual Incentive Compensation Plan (Incorporated by reference to Exhibit 10.61 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2007).
10 .55*	2008 Management Annual Incentive Compensation Plan (Incorporated by reference to Appendix B to the Registrant s Proxy Statement for the 2008 Annual Meeting of Shareholders, filed March 27, 2008).
10 .56*	The Registrant s Deferred Compensation Plan (Incorporated by reference to Exhibit 10.30 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10 .57*	First Amendment to the Registrant s Deferred Compensation Plan (Incorporated by reference to Exhibit 10.49 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2004).
10 .58*	Letter Agreement, dated as of March 1, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed March 4, 2005).
10 .59*	Restated Employment Agreement effective December 31, 2009 by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed December 24, 2009).
10 .60*	Restated Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Richard A. Navarre (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K, filed December 31, 2008).
10 .61*	Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Michael C. Crews (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed December 31, 2008).
10 .62*	Restated Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Sharon D. Fiehler (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed December 31, 2008).
10 .63*	Letter Agreement, dated as of December 22, 2006, by and between the Registrant and Eric Ford (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10 .64*	Form of Restricted Stock Agreement Exhibit A (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10 .65*	Form of Restricted Stock Agreement Exhibit B (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K, filed December 29, 2006).
10 .66*	Restated Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Eric Ford (Incorporated by reference to Exhibit 10.5 of the Registrant s Current Report on Form 8-K, filed December 31, 2008).
10 .67*	Restated Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Alexander C. Schoch (Incorporated by Reference to Exhibit 10.59 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2008).
10 .68*	Indemnification Agreement, dated as of December 5, 2002, by and between Registrant and William E. James (Incorporated by reference to Exhibit 10.34 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).
10 .69*	Indemnification Agreement dated as of December 5, 2002, by and between Registrant and Henry E. Lentz (Incorporated by reference to Exhibit 10.35 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).
10 .70*	Indemnification Agreement dated as of December 5, 2002, by and between Registrant and William C. Rusnack (Incorporated by reference to Exhibit 10.36 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).

10 .71*	Indemnification Agreement dated as of December 5, 2002, by and between Registrant and Alan H. Washkowitz (Incorporated by reference to Exhibit 10.39 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).

Exhibit No.	Description of Exhibit
10 .72*	Indemnification Agreement dated as of December 5, 2002, by and between Registrant and Richard A. Navarre (Incorporated by reference to Exhibit 10.40 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).
10 .73*	Indemnification Agreement dated as of January 16, 2003, by and between Registrant and Robert B. Karn III (Incorporated by reference to Exhibit 10.41 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).
10 .74*	Indemnification Agreement dated as of January 16, 2003, by and between Registrant and Sandra A. Van Trease (Incorporated by reference to Exhibit 10.42 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2002).
10 .75*	Indemnification Agreement dated as of March 22, 2004, by and between Registrant and William A. Coley (Incorporated by reference to Exhibit 10.53 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
10 .76*	Indemnification Agreement dated as of April 8, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed April 14, 2005).
10 .77*	Indemnification Agreement dated July 21, 2005, by and between the Registrant and John F. Turner (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed August 5, 2005).
10 .78*	Indemnification Agreement dated as of March 2, 2009 by and between the Registrant and M. Frances Keeth (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on March 2, 2009).
10 .79*	Indemnification Agreement dated as of July 23, 2009 by and between Peabody Energy Corporation and Robert A. Malone (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on July 23, 2009).
10 .80*	Indemnification Agreement dated as of June 19, 2008, by and between the Registrant and Michael C. Crews (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K, filed July 29, 2008).
10 .81*	Indemnification Agreement dated as of October 22, 2008, by and between the Registrant and Sharon D. Fiehler (Incorporated by reference to Exhibit 10.72 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2008).
10 .82*	Indemnification Agreement dated as of October 22, 2008, by and between the Registrant and Eric Ford (Incorporated by reference to Exhibit 10.73 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2008).
10 .83*	Indemnification Agreement dated as of October 22, 2008, by and between the Registrant and Alexander C. Schoch (Incorporated by reference to Exhibit 10.74 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2008).
10 .84*	Peabody Investments Corp. Supplemental Employee Retirement Account (Incorporated by reference to Exhibit 10.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10 .85	Second Amended and Restated Receivables Purchase Agreement, dated as of December 15, 2009, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, Market Street Funding LLC, as Issuer, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on December 21, 2009).
21	List of Subsidiaries.

23	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31 .1	Certification of periodic financial report by the Registrant s Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31 .2	Certification of periodic financial report by the Registrant s Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit No.	Description of Exhibit
32.1	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant s Chief Executive Officer.
32.2	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant s Chief Financial Officer.
101	Interactive Data File (Form 10-K for the year ended December 31, 2009 furnished in XBRL). Users of this data are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited and unreviewed.

* These exhibits constitute all management contracts, compensatory plans and arrangements required to be filed as an exhibit to this form pursuant to Item 15(a)(3) and 15(b) of this report.

Filed herewith.