PEABODY ENERGY CORP
Form 10-K
February 28, 2011

Table of Contents

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

Form 10-K

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

Commission File Number 1-16463

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

Delaware	**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. o

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

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

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE

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

Table of Contents

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

effects of acquisitions or divestitures;

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

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

Table of Contents

litigation, including claims not yet asserted;

terrorist attacks or threats;

impacts of pandemic illnesses; and

other factors, including those discussed in Legal Proceedings, set forth in Item 3 of this report and Risk Factors, set forth in Item 1A of this report.

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

TABLE OF CONTENTS

		Page
	PART I.	
Item 1.	Business	2
Item 1A.	Risk Factors	16
Item 1B.	Unresolved Staff Comments	25
Item 2.	Properties	25
Item 3.	Legal Proceedings	31
Item 4.	[Removed and Reserved]	31
	Executive Officers of the Company	31
	PART II.	
Item 5.	Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	33
Item 6.	Selected Financial Data	34
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	36
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	55
Item 8.	Financial Statements and Supplementary Data	58
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	58
Item 9A.	Controls and Procedures	58
Item 9B.	Other Information	61
	PART III.	
Item 10.	Directors, Executive Officers and Corporate Governance	65
Item 11.	Executive Compensation	65
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	65
Item 13.	Certain Relationships and Related Transactions, and Director Independence	66
Item 14.	Principal Accounting Fees and Services	66
	PART IV.	
Item 15.	Exhibits, Financial Statement Schedules	66

EX-10.43
EX-21
EX-23
EX-31.1
EX-31.2
EX-32.1
EX-32.2
EX-101 INSTANCE DOCUMENT
EX-101 SCHEMA DOCUMENT
EX-101 CALCULATION LINKBASE DOCUMENT
EX-101 LABELS LINKBASE DOCUMENT
EX-101 PRESENTATION LINKBASE DOCUMENT
EX-101 DEFINITION LINKBASE DOCUMENT

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

PART I

Item 1. *Business.*

History and Development of Business

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

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

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

We have four core strategies to achieve growth:

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

2) Capitalizing on organic growth opportunities;

3) Expanding in high-growth global markets; and

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

Segments

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

Mining Segments

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

Table of Contents

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

U.S. Mining Operations

Australian Mining Operations

Table of Contents

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

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

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

Legend:

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

* Mine is operated by a contract miner

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

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

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

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

Table of Contents

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

Trading and Brokerage Segment

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

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

Corporate and Other Segment

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Coal Supply Agreements

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

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

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

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

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

Transportation

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

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

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

Suppliers

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

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

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

Technical Innovation

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

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

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

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

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

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

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

Competition

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

Employees

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

Working Capital

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

Regulatory Matters U.S.

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

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

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

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

Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion materials generated at electric utility and independent power producing facilities. In May 2000, the EPA concluded that coal combustion materials do not warrant regulation as hazardous wastes under RCRA. The EPA has retained the hazardous waste exemption for these materials. The EPA is evaluating national waste guidelines for coal combustion materials placed at a mine. National guidelines for mine-fills may affect the cost of ash placement at mines. The EPA revisited its May 2000 determination and proposed new requirements for coal combustion residue (CCR) management on June 21, 2010. That proposal contains two options: (1) to continue to regulate CCR as a non-hazardous waste, or (2) to regulate CCR as special waste under the hazardous waste regulations.

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

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

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. In addition, the storage of explosives is subject to strict federal regulatory requirements.

Regulatory Matters Australia

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

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

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

Table of Contents

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

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

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

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

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

Regulatory Matters Mongolia

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

Global Climate

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

Table of Contents

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

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

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

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

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

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

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

Additional Information

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

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

Item 1A. *Risk Factors.*

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

Risks Associated with Our Operations

A decline in coal prices could negatively affect our profitability.

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The possibility exists that new legislation and/or regulations and orders related to the environment or employee health and safety may be adopted and may materially adversely affect our mining operations, our cost structure and/or our customers ability to use coal. New legislation or administrative regulations (or new interpretations by the relevant government authorities of existing laws and regulations), including proposals related to the protection of the environment or the reduction of greenhouse gas emissions that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or

Table of Contents

incur increased costs. Some of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser s plant or results in specified increases in the cost of coal or its use. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

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

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

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

Our future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable.

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

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

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

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

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

Risks Associated with Our Indebtedness

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

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

Our financial performance could be adversely affected by our debt.

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

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

increasing our vulnerability to general adverse economic and industry conditions;

- requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal and interest on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, business development, Btu Conversion and clean coal technology projects or other general corporate uses;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, business development, Btu Conversion and clean coal technology projects or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

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

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

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

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

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

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

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

Table of Contents

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

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

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

Other Business Risks

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

Coal Reserves

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

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.

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

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

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

Proven (Measured) Reserves Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so close and the geographic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

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

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

Table of Contents

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

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

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

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

Table of Contents

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

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

(Tons in Millions)

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

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

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

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

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

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

Item 3. *Legal Proceedings.*

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

Item 4. *[Removed and Reserved]*

Executive Officers of the Company

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

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

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

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

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

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

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

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

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

PART II

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

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

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

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

Dividend Policy

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

Share Repurchases

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

Table of Contents

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

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

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

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

Item 6. *Selected Financial Data.*

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

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

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

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

Table of Contents

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

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

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

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

Table of Contents

Adjusted EBITDA is calculated as follows (unaudited):

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

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

Overview

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

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

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

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

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

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

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

Table of Contents

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

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

Summary

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

- Seaborne coal demand increased an estimated 13% in 2010, led by a 32% recovery in global metallurgical coal demand;

- Pacific thermal coal demand for electricity generation rose 15% in 2010, while the Atlantic market declined 10%;

- Benchmark pricing of high quality, hard coking coal in the seaborne market has ranged between $200 to $225 per tonne since April 2010;

- The benchmark prompt seaborne thermal coal price in Newcastle, Australia rose 34% in 2010;

- U.S. coal generation accounted for nearly two-thirds of the growth in total power output in 2010 due to new coal-fueled generation, favorable weather, and a partial reversal of 2009 s coal-to-gas switching; and

- Indexed U.S. coal prices rose in 2010 in all regions, with increases ranging from 30 to 50%.

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

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

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

Tons Sold

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

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

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

Table of Contents

Revenues

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

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

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

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

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

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

Segment Adjusted EBITDA

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

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

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

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

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

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

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

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

Income From Continuing Operations Before Income Taxes

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

	Year Ended December 31,		Increase (Decrease) to Income	
	2010	**2009**	**$**	**%**
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 2,169.8	$ 1,634.6	$ 535.2	32.7%
Corporate and Other Adjusted EBITDA[1]	(354.7)	(344.5)	(10.2)	(3.0)%
Depreciation, depletion and amortization	(440.9)	(405.2)	(35.7)	(8.8)%
Asset retirement obligation expense	(48.5)	(40.1)	(8.4)	(20.9)%
Interest expense	(222.1)	(201.2)	(20.9)	(10.4)%
Interest income	9.6	8.1	1.5	18.5%
Income from continuing operations before income taxes	$ 1,113.2	$ 651.7	$ 461.5	70.8%

(1) Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income (loss) from our joint ventures, net gains on asset disposals or exchanges, costs associated with past mining obligations and revenues and expenses related to our other commercial activities such as generation development and Btu Conversion development costs.

Income from continuing operations before income taxes was higher compared to the prior year primarily due to the higher Total Segment Adjusted EBITDA discussed above, partially offset by lower Corporate and Other Adjusted EBITDA and higher depreciation, depletion and amortization expense and interest expense as discussed below:

Corporate and Other Adjusted EBITDA: higher expense was primarily driven by a current year increase in selling and administrative expenses due to costs to support our business development and international expansion (e.g. headcount, travel, professional services, legal). We also incurred increased post mining costs driven by higher retiree healthcare amortization of actuarial losses and interest cost. These items were partially offset by improved results from equity affiliates primarily due to prior year losses of $54.6 million related to our equity investment in Carbones del Guasare, which included a $34.7 million impairment loss and $19.9 million of operating losses. See Note 1 to our consolidated financial statements for additional information.

Table of Contents

Depreciation, depletion and amortization: higher compared to the prior year due to increased production at our Australian mines with higher per-ton depletion rates reflecting higher demand and additional depreciation expense associated with our new Bear Run Mine (commissioned in the second quarter of 2010).

Interest expense: higher primarily due to refinancing charges ($9.3 million) associated with our new five-year Credit Facility and charges ($8.4 million) associated with the extinguishment and refinancing of $650.0 million of senior notes.

Net Income Attributable to Common Stockholders

The following table presents net income attributable to common stockholders for the years ended December 31, 2010 and 2009:

	Year Ended December 31,		Increase (Decrease) to Income	
	2010	2009	$	%
	(Dollars in millions)			
Income from continuing operations before income taxes	$ 1,113.2	$ 651.7	$ 461.5	70.8%
Income tax provision	(308.1)	(193.8)	(114.3)	(59.0)%
Income from continuing operations, net of income taxes	805.1	457.9	347.2	75.8%
Income (loss) from discontinued operations, net of income taxes	(2.9)	5.1	(8.0)	156.9%
Net income	802.2	463.0	339.2	73.3%
Net income attributable to noncontrolling interests	(28.2)	(14.8)	(13.4)	(90.5)%
Net income attributable to common stockholders	$ 774.0	$ 448.2	$ 325.8	72.7%

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

Income tax provision was impacted by the following:

Increased expense due to higher current year earnings ($161.5 million) and current year income tax resulting from foreign earnings repatriation ($84.5 million), partially offset by

A change in the valuation allowance ($46.4 million) related primarily to alternative minimum tax credits, lower expense associated with the remeasurement of non-U.S. tax accounts as a result of the larger increase in the Australian exchange rate against the U.S. dollar in the prior year compared to the current year ($26.8 million) as set forth in the table below, the favorable rate difference resulting from higher foreign generated income in the current year ($42.5 million), and lower expense in the current year due to the reduction of our gross unrecognized tax benefit resulting from the completion of the Internal Revenue Service examination of the 2005 federal income tax year ($15.2 million).

	December 31,			Rate Change	
	2010	2009	2008	2010	2009
Australian dollar to U.S. dollar exchange rate	$ 1.0163	$ 0.8969	$ 0.6928	$ 0.1194	$ 0.2041

Income (loss) from discontinued operations for 2010 reflects a loss of $2.9 million as compared to income of $5.1 million in 2009 due primarily to a coal excise tax refund receivable of approximately $35 million recorded in 2009, partially offset by operating losses and loss on disposal of our Australian Chain Valley Mine in 2009.

Table of Contents

Other

The fair value of our foreign currency hedges increased approximately $434 million in 2010 mostly due to the strengthening of the Australian dollar against the U.S. dollar in the current year. The increase is reflected in Other current assets and Investments and other assets in the consolidated balance sheets.

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 third highest in our 127-year history, only trailing 2008 and 2010. We also ended 2009 with total available liquidity of $2.5 billion. We continued 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.

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)%

Table of Contents

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)%
Corporate and 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 the 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 the 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 the 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:

	Year Ended December 31,		Increase (Decrease) to Income	
	2009	2008	$	%

	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 1,634.6	$ 2,094.1	$ (459.5)	(21.9)%
Corporate and Other Adjusted EBITDA[1]	(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)%

Table of Contents

(1) Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income (loss) from our joint ventures, net gains on asset disposals or exchanges, costs associated with past mining obligations and revenues and expenses related to our other commercial activities such as generation development and Btu Conversion development costs.

Income from continuing operations before income taxes decreased from the 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.

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 the prior year due to lower variable interest rates on our Term Loan Facility and accounts receivable securitization program and lower average borrowings on our Revolver.

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:

	Year Ended December 31,		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)%

Table of Contents

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.

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.

Outlook

Near-Term Outlook

The World Bank estimates global economic activity, as measured by gross domestic product (GDP), expanded 3.9% in 2010. Global GDP is projected to grow another 3.3% in 2011 and 3.6% in 2012, with developing economies, led by China and India, expanding 6% or more in each year, more than twice the growth expected for high income countries. China s GDP is projected by the World Bank to grow 10.0% in 2010 and 8.7% in 2011. India, the world s second fastest growing economy, is projected by the World Bank to grow 9.5% in 2010 and 8.4% in 2011.

According to the World Steel Association (WSA), global steel use was expected to increase 13.1% in 2010, followed by another 5.3% in 2011 to a record 1.3 billion tonnes. The WSA forecasts India s steel demand would rise 8.2% in 2010 and 13.6% in 2011. Similar trends are apparent in steel production. For 2010, global steel production exceeded prior year levels by 15%, led by Asia-based production (Japan, Taiwan, South Korea, China and India). Industry reports indicate China, the world s largest steel consumer, is expected to grow its steel use 11% in 2010, and is projected to grow a further 8% to 9% in 2011.

Industry reports forecast nearly 85 gigawatts of new coal-fueled generation globally were due to come on line during 2010; nearly 80% of which were in China and India. New global coal-fueled generation for 2010 is estimated to require approximately 290 million tons of coal annually. For 2011, approximately 90 gigawatts are expected to be under construction and/or come online, requiring more than 340 million tons of coal. China and India continue to make up the vast majority.

Given the pace of coal demand in the Pacific throughout 2010, coupled with late-2010 weather-related demand increases in the Northern Hemisphere and supply constraints in key nations such as Australia, Indonesia, South Africa, South America and Canada, prices for seaborne metallurgical and thermal coal have been increasing. High quality, hard coking coal prices have increased from $129 per tonne for annual contracts commencing April 2009, to quarterly (April, July, October 2010) prices ranging between $200 and $225 per tonne, with January 2011 spot price exceeding $350 per tonne. Prompt index prices for Australian seaborne thermal coal rose 34% by year-end 2010, and have risen another 10% as of January 18, 2011.

Accordingly to the Energy Information Administration s (EIA) Short-Term Energy Outlook, 2011 coal consumption, coal production and utility coal stockpiles in the U.S. are projected to be essentially on par with 2010. U.S. growth is projected to resume in 2012, with the increased consumption being matched by higher production, resulting in minimal change to utility coal stockpiles.

U.S. natural gas consumption increased 5.5% and production rose approximately 4% in 2010, according to the EIA. Rising supplies combined with persistently high inventory levels have resulted in subdued gas prices. The NYMEX Henry Hub spot price averaged $4.52 per thousand cubic feet in 2010, above 2009 s average $4.06 per thousand cubic feet yet 67% below the 2007 2009 average.

The EIA also projects that natural gas consumption, production and storage levels will decline slightly in 2011. Like coal, natural gas consumption is expected to grow in 2012, approximately 1.6% to 66.5 billion cubic feet. The projected production decline in 2011 and higher natural gas consumption in 2012 are expected to lead to strengthening natural gas prices. As natural gas prices begin to rise, natural gas production is expected to rebound, growing approximately 2% in 2012.

U.S. shale natural gas development continues in the U.S. accounting for approximately 20% of gas supply in 2010 and is estimated by the PIRA Energy Group to grow to over 30% of gas supply over the next several years. This is expected to lead to continued growth in gas-fired electricity in the U.S.

As of January 25, 2011, we had 7 to 8 million tons of our targeted 2011 metallurgical coal volumes and 6 to 7 million tons of our planned seaborne thermal coal volumes available for pricing in the last three quarters of 2011. For 2012, all of our expected metallurgical coal sales and 12 to 13 million tons of our estimated seaborne thermal coal sales are available to price. In the U.S., we have modest amounts of coal to price in 2011, 35% to 40% in 2012 and 75% to 85% in 2013. We may continue to adjust our production levels in response to change in market demand.

We continue to manage costs and operating performance in an effort to mitigate external cost pressures, geologic conditions and potential shipping delays resulting from adverse port and rail performance. We may have higher per ton costs as a result of suboptimal 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. Reductions in the relative cost of other fuels, including natural gas, could impact the use of coal for electricity generation. See Cautionary Notice Regarding Forward-Looking Statements and Item 1A. Risk Factors of this report for additional considerations regarding our outlook.

We rely on ongoing access to 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, bank guarantees, 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.

Dodd-Frank Act. On July 21, 2010, President Obama signed into law the Dodd-Frank Act, which includes a number of provisions applicable to us in the areas of corporate governance, executive compensation and mine safety and extractive industries disclosure. In addition, the Dodd-Frank Act imposes additional regulation of financial derivatives transactions that may apply to our hedging and our Trading and Brokerage activities. Although the Dodd-Frank Act became generally effective upon its enactment, many provisions have extended implementation periods and delayed effective dates and require further action by the federal regulatory authorities. As a result, in many respects the ultimate impact of the Dodd-Frank Act on us will not be fully known for an extended period of time. We do expect that the Dodd-Frank Act will increase compliance and transaction costs associated with our hedging and Trading and Brokerage activities.

Minerals Resource Rent Tax. On May 2, 2010, the Australian government released a report on Australia s Future Tax System, which included a recommendation to replace the current resource taxing arrangements imposed on non-renewable resources by the Australian federal and state governments with a uniform resource rent tax (the Resource Tax) imposed and administered by the Australian government. As proposed, the Resource Tax would be profit-based and would apply to non-renewable resources projects, including existing projects. On July 2, 2010, the Australian government announced changes to the Resource Tax and proposed a new minerals resource rent tax (the MRRT). The MRRT would still be profit-based, but measures were introduced to lessen the impact of the MRRT. The Australian government and major industry policy makers are actively engaged to work through various structural aspects of the proposed MRRT together with detailed implementation issues. The Committee charged with consulting with industry and preparing recommendations as to the final form of the MRRT submitted its report in late December 2010. The Committee s recommendations largely endorse the mining industry s understanding as to what was agreed with the federal government prior to the federal election. The Committee s recommendations notwithstanding, it remains to be seen whether the federal government will adopt all recommendations, in particular the recommendation that all state royalties (current and future) are creditable against MRRT payments. MRRT is not yet law in Australia; exposure draft legislation is expected in mid-2011. Following the release of the draft legislation, industry participants will engage in further consultation with the federal government as required. The draft law is expected to be presented to the Australian Parliament in late 2011, and if the MRRT becomes law, it is intended to become effective July 1, 2012. If the MRRT were to become law, it may affect the financial performance of our Australian operations from the effective date forward.

Long-Term Outlook

Our long-term global outlook remains positive. According to the BP Statistical Review of World Energy, coal has been the fastest-growing fuel in the world for the past decade.

The International Energy Agency (IEA) estimates in its World Energy Outlook issued in November 2010, current policies scenario, that world primary energy demand will grow 47% between 2008 and 2035. Demand for coal is projected to rise 59%, outpacing the growth rate of oil, natural gas, nuclear, hydro and biomass. China and India alone account for more than 85% of the 2008 2035 coal-based primary energy demand growth.

Under the current policies scenario, the IEA expects coal to retain its strong presence as a fuel for the power sector worldwide. Coal s share of the power generation mix was 41% in 2008. By 2035, the IEA estimates coal s fuel share to be 43% as it continues to have the largest share of worldwide electric power production. Currently, we estimate approximately 390 gigawatts of coal-fueled electricity generating plants are planned or under construction around the world, with expected online dates ranging between 2011 and 2015. When complete, those plants would require an estimated 1.4 billion tons of annual coal demand. In the U.S., while some planned coal-based plants have been cancelled, 13 gigawatts of new coal-based generating capacity have been completed in 2010 or are under construction with completion dates of 2011 2013, representing approximately 55 million tons of annual coal demand once they become operational.

The IEA projects global natural gas-fueled electricity generation will have a compound annual growth rate of 2.5%, from 4.3 trillion kilowatt hours in 2008 to 8.3 trillion kilowatt hours in 2035. The total amount of electricity generated from natural gas is expected to be approximately one-half the total for coal, even in 2035. Renewables are projected to comprise 23% of the 2035 fuel mix versus 19% in 2008. Nuclear power is expected to grow 52%, however its share of total generation is expected to fall from 13.5% to 11% between

2008 and 2035. Generation from liquid fuels is projected to decline an average of 2.2% annually to 1.5% of the 2035 generation mix.

We believe that Btu Conversion applications such as CTG and CTL plants represent an avenue for potential long-term industry growth. Several CTG and CTL facilities are currently under development in China and India.

We continue to support clean coal technology development toward the ultimate goal of near-zero emissions, and we are advancing more than a dozen projects and partnerships 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 five to ten commercial CCS projects by 2016.

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

Liquidity and Capital Resources

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. Along with cash and cash equivalents, our liquidity includes the available balances from our Revolver under the Credit Facility, accounts receivable securitization program and a bank overdraft facility in Australia. Our liquidity is also impacted by activity under certain bilateral cash collateralization arrangements. As of December 31, 2010, we had cash and cash equivalents of $1.3 billion and our total available liquidity was $2.7 billion. We currently expect that our cash on hand, cash flow from operations and available liquidity will be sufficient to meet our anticipated capital requirements during the next 12 months and for the foreseeable future, as described below in Capital Requirements. In addition to the above items, alternative sources of liquidity include the ability to offer and sell certain securities under our shelf registration (as described below).

In 2010, we replaced our previous $1.8 billion revolving credit facility with a $1.5 billion Revolver under a new Credit Facility (as described below). Also, additional information on our accounts receivable securitization program and bilateral cash collateralization arrangements can be found in the Off-Balance Sheet Arrangements section.

Credit Facility. On June 18, 2010, we entered into a Credit Agreement which established a $2.0 billion Credit Facility and replaced our third amended and restated credit agreement dated September 15, 2006. The Credit Agreement provides for a $1.5 billion Revolver and a $500.0 million term loan facility (Term Loan). We have the option to request an increase in the capacity of the Credit Facility (but no lender is obligated to increase its commitment to us), provided the aggregate increase for the Revolver and Term Loan does not exceed $250.0 million, the minimum amount of the increase is $25.0 million, and certain other conditions are met under the Credit Agreement. The Revolver also includes a swingline sub-facility where up to $50.0 million is available for same-day borrowings. The

Revolver commitments and the Term Loan under the Credit Facility will mature on June 18, 2015. The Term Loan is subject to quarterly repayment of 1.25% per quarter beginning in the fourth quarter of 2010, with the final payment of all amounts outstanding (including accrued interest) being due five years from the date of the execution of the Credit Agreement.

Table of Contents

The Revolver replaced our previous $1.8 billion revolving credit facility and the Term Loan replaced our previous term loan facility (the previous term loan had a balance of $490.3 million at the time of replacement and at December 31, 2009). We recorded $21.9 million in deferred financing costs which are being amortized to interest expense over the five year term of the Credit Facility, and incurred refinancing charges of $9.3 million, which is classified as interest expense in the consolidated statements of operations.

There were no borrowings outstanding under the Revolver in 2010 or 2009, or at December 31, 2010. However, we had $67.6 million of outstanding letters of credit as of December 31, 2010, which effectively reduced our borrowing capacity under the Revolver by the same amount.

See Note 8 to our consolidated financial statements for additional information on the new Credit Facility.

Shelf Registration. We have an effective shelf registration statement on file with the SEC for an indeterminate number of securities that is effective for three years (expires August 7, 2012), 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 Requirements

Our primary uses of cash include our cash costs of coal production, capital expenditures, coal reserve lease and royalty payments, debt service costs (interest and principal), lease obligations, take or pay obligations and costs related to past mining obligations. Future dividends and share repurchases, among other restricted items, are subject to limitations imposed in the covenants of certain of our debt instruments. We generally fund our capital expenditure requirements with cash generated from operations.

Capital Expenditures. Capital expenditures for 2011 are anticipated to be $900 to $950 million; including $500 to $550 million earmarked for new mines, expansion and extension projects. Approximately 70% of the growth and expansion capital is targeted for various Australian projects for metallurgical and thermal coal, with the remainder in the U.S. Estimated capital expenditures also include funding for our share of construction costs for Prairie State.

Prairie State. We spent $76.0 million during 2010 representing our 5.06% share of the construction costs. Included in Investments and other assets in the consolidated balance sheets as of December 31, 2010 and 2009, are costs of $202.5 million and $126.5 million, respectively. Our share of total construction costs for Prairie State is expected to be approximately $250 million, with most of the remaining funding expected in 2011.

GreenGen. During 2010, we spent $3.1 million representing our 6.0% share of the construction costs, which is reflected as capitalized development costs as part of Investments and other assets in the consolidated balance sheet. There were no expenditures for GreenGen for 2009. Our share of total construction costs for GreenGen is expected to be approximately $60 million.

Dividends. We have declared and paid quarterly dividends since our initial public offering in 2001. In January 2011, our Board of Directors approved a dividend of $0.085 per share of common stock, payable on March 3, 2011. The declaration and payment of dividends and the amount of dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors.

Pension Contributions. During 2010, we made contributions of $112.6 million, which includes our estimate of required contributions for 2011 (based on current assumptions).

Share Repurchase Program. At December 31, 2010, our available capacity for share repurchases was $700.4 million, and our Chairman and Chief Executive Officer has authority to direct us to repurchase up to $100 million of our common stock outside of the share repurchase program. While no such share repurchases were made in 2010, 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.

Table of Contents

NCIG. Financing for phase one of stage two of construction closed in 2010 with us providing our pro-rata share of funding of $59.7 million Australian dollars ($54.8 million U.S. dollars). NCIG may further expand the coal transloading facility s capacity which could require us to fund our pro-rata share in a similar manner.

Senior Notes. On August 25, 2010, we completed a $650.0 million offering of 6.5% 10-year Senior Notes due September 2020 (the Notes). The Notes are senior unsecured obligations and rank senior in right of payment to any subordinated indebtedness; equally in right of payment with any senior indebtedness; effectively junior in right of payment to our 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 our subsidiaries that do not guarantee the Notes. Interest payments are scheduled to occur on March 15 and September 15 of each year, commencing on March 15, 2011.

The Notes are jointly and severally guaranteed by nearly all of our domestic subsidiaries, as defined in the note indenture. The note indenture contains covenants that, among other things, limit our 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 and any accrued unpaid interest to the redemption date.

We used the net proceeds from the issuance of the Notes, after deducting underwriting discounts and expenses, and cash on hand, to extinguish our previously outstanding $650.0 million aggregate principal 6.875% Senior Notes formerly due in March 2013 (the 2013 Notes). All of the 2013 Notes were either tendered or redeemed in 2010. We recognized debt extinguishment costs of $8.4 million, which are classified as interest expense in the consolidated statements of operations. The issuance of the Notes and the extinguishment of the 2013 Notes allowed us to lengthen the maturity of our senior indebtedness and lower the coupon rate.

See Note 8 to our consolidated financial statements for additional information on the Notes.

Total Indebtedness. Our total indebtedness as of December 31, 2010 and 2009, consisted of the following:

	December 31,	
	2010	**2009**
	(Dollars in millions)	
Term Loan	$ 493.8	$ 490.3
6.875% Senior Notes due March 2013		650.0
5.875% Senior Notes due April 2016	218.1	218.1
7.375% Senior Notes due November 2016	650.0	650.0
6.5% Senior Notes due September 2020	650.0	
7.875% Senior Notes due November 2026	247.2	247.1
6.34% Series B Bonds due December 2014	12.0	15.0
6.84% Series C Bonds due December 2016	33.0	33.0
Convertible Junior Subordinated Debentures due 2066	373.3	371.5
Capital lease obligations	69.6	67.5
Fair value hedge adjustment	2.2	8.4
Other	0.8	1.4
Total	$ 2,750.0	$ 2,752.3

We were in compliance with all of the covenants of the Credit Facility, the 5.875% Senior Notes, the 7.375% Senior Notes, the 6.5% Senior Notes, the 7.875% Senior Notes and the Debentures as of December 31, 2010.

Table of Contents

Historical Cash Flows

	Year Ended December 31,		Increase (Decrease) to Cash Flow	
	2010	2009	$	%
	(Dollars in millions)			
Net cash provided by operating activities	$ 1,087.1	$ 1,050.2	$ 36.9	3.5%
Net cash used in investing activities	(703.6)	(406.5)	(297.1)	73.1%
Net cash used in financing activities	(77.1)	(104.6)	27.5	(26.3)%

Operating Activities. The changes from the prior year were driven by the following:

Strong operating cash flows generated from our Australian Mining operations driven by higher volumes and pricing; partially offset by

Increased margin posted for our derivative trading instruments;

Lower utilization of our accounts receivable securitization program in the current year; and

Higher pension payments in the current year.

Investing Activities. The changes from the prior year were driven by the following:

Higher current year capital spending of $296.4 million related primarily to our Bear Run Mine;

Current year net cash outflows related to our pro-rata share of funding for the NCIG coal transloading facility; and

The collection of a note receivable of $30.0 million in the prior year; partially offset by

Federal coal lease expenditures of $123.6 million in the prior year.

Financing Activities. The increase compared to the prior year was primarily due to the excess tax benefits related to share-based compensation of $51.0 million, partially offset by the payment of debt issuance costs of $32.2 million in the current year related to our Credit Facility refinancing and the offering of the Notes. The proceeds from long-term debt include $500.0 million from the Term Loan and $641.9 million of net proceeds from the issuance of the Notes. These proceeds were used to pay off the $490.3 million balance due on our previous term loan facility and the previously outstanding $650.0 million 2013 Notes.

Other Long-Term Debt. A description of our other debt instruments is described in Note 8 to the consolidated financial statements.

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2010:

		Payments Due By Year			
	Total	Less than 1 Year	2 - 3 Years	4 - 5 Years	More than 5 Years
			(Dollars in millions)		
Long-term debt obligations (principal and interest)	$ 5,621.6	$ 213.4	$ 436.6	$ 789.4	$ 4,182.2
Capital lease obligations (principal and interest)	74.6	17.0	42.1	15.5	
Operating lease obligations	455.8	95.6	147.2	106.1	106.9
Unconditional purchase obligations(1)	458.2	406.7	51.5		
Coal reserve lease and royalty obligations	62.0	7.2	14.3	10.2	30.3
Take or pay obligations(2)	2,892.9	217.5	465.9	425.7	1,783.8
Other long-term liabilities(3)	2,204.1	154.6	301.7	298.7	1,449.1
Total contractual cash obligations	$ 11,769.2	$ 1,112.0	$ 1,459.3	$ 1,645.6	$ 7,552.3

(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. The purchase obligations for capital expenditures relate to new mines and expansion and extension projects in Australia and the U.S.

(2) Represents various long- and short-term take or pay arrangements associated with rail and port commitments for the delivery of coal including amounts relating to export facilities.

(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.

We do not expect any of the $111.0 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.

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, bank guarantees and surety bonds and our accounts receivable securitization program. 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.

Accounts Receivable Securitization. We have an accounts receivable securitization program (securitization program) through our wholly-owned, bankruptcy-remote subsidiary (Seller). Under the securitization program, beginning in 2010, we contribute, on a revolving basis, trade receivables of most of our U.S. subsidiaries to the Seller, which then sells the receivables in their entirety to a consortium of unaffiliated asset-backed commercial paper conduits (the Conduits). After the sale, we, as servicer of the assets, collect the receivables on behalf of the Conduits for a nominal servicing fee. We utilize proceeds from the sale of our accounts receivable as an alternative to short-term borrowings under our Credit Facility, effectively managing our overall borrowing costs and providing an additional source for working capital. The securitization program was renewed in May 2009 and amended in December 2009 in order to qualify for sale accounting under a newly adopted accounting standard related to financial asset transfers. Prior to amending the securitization program, we sold senior undivided interests in certain of our accounts receivable and retained subordinated interests in those receivables. The current securitization program 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 Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Of the receivables sold to the Conduits, a portion of the amount due to the Seller is deferred until the ultimate collection of the underlying receivables. During the year ended December 31, 2010, we received total consideration of $4,576.3 million related to accounts receivable sold under the securitization program, including $2,460.1 million of cash up front from the sale of the receivables, an additional $1,953.6 million of cash upon the collection of the underlying receivables, and $162.6 million that had not been collected at December 31, 2010 and was recorded at fair value, which approximates carrying value. The reduction in accounts receivable as a result of securitization activity with the Conduits was $150.0 million at December 31, 2010 and $254.6 million at December 31, 2009.

The securitization activity has been reflected in the consolidated statements of cash flows as operating activity because both the cash received from the Conduits upon sale of receivables as well as the cash received from the Conduits upon the ultimate collection of receivables are not subject to significantly different risks given the short-term nature of our trade receivables. We recorded expense associated with securitization transactions of $2.4 million, $4.0 million and $10.8 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Other Off-Balance Sheet Arrangements. In 2010, we added standalone credit facilities with multiple banks to allow us to obtain letters of credit and bank guarantees in support of certain operations outside the U.S. As of December 31, 2010, the total capacity under these new facilities, both committed and uncommitted, was approximately $324 million, of which approximately $141 million was utilized (based on the U.S. dollar exchange rate at December 31, 2010). Also during 2010, we entered into a bilateral cash collateralized agreement in support of certain letters of credit whereby we posted cash collateral in lieu of utilizing our Credit Facility. Such cash collateral is classified within cash and cash equivalents given our ability to substitute letters of credit at any time for this cash collateral.

See Note 19 to our consolidated financial statements for a discussion of our guarantees.

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 U.S. GAAP. We are also required under U.S. GAAP to 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.

Postretirement Benefit and Pension 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 11 and 12 to our consolidated financial statements. Liabilities for postretirement benefit costs are not funded. Our pension obligations are funded in accordance with the provisions of applicable law. Expense for the year ended December 31, 2010 for pension and postretirement liabilities totaled $115.6 million, while funding payments were $187.9 million.

Each of these liabilities is 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]	$ 7.8	$ (6.6)
Effect on total postretirement benefit obligation[1]	$ 112.5	$ (94.4)

Table of Contents

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)]	$ (51.1)	$ 58.8

(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 11.93 years at December 31, 2010.

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, 2010 was $48.5 million, and payments totaled $14.1 million. See Note 10 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 level hierarchy, Levels 1, 2 and 3. Level 3 fair value measurements are those where inputs are unobservable, or observable but cannot be market-corroborated, requiring us to make assumptions about pricing by market participants. 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, 2010 and 2009, 3% and 5%, respectively, of our net financial assets were categorized as Level 3. See Notes 4 and 5 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, 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 direct and brokered trading of coal, ocean freight and fuel-related commodities in over-the-counter markets (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, 2010 and 2009.

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.

In 2010, we modified our VaR methodology to be in line with our global trading strategy. The previous methodology used an additive approach whereby the domestic portfolio and the international portfolio were calculated separately and then added together to arrive at our total global VaR. The new methodology explicitly considers correlation measures between the domestic and the international portfolios to consolidate our total global VaR. The high, low and average VaR for the year ended December 31, 2010 is set forth in the table below under the previous and new methodology :

Year Ended December 31, 2010	**Low**	**High**	**Average**
	(Dollars in millions)		
Previous Methodology	$ 4.5	$ 37.6	$ 10.1
New Methodology	$ 3.4	$ 18.8	$ 7.0

As of December 31, 2010, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	**Percentage of Portfolio Total**
2011	70%
2012	21%
2013	3%
2014	4%
2015	2%
	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

Coal Trading. The fair value of our coal trading assets and liabilities reflects adjustments for nonperformance and credit risk. Our exposure is substantially with electric utilities, 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 (margin), 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.

Non-Coal Trading. The fair value of our non-coal trading derivative assets and liabilities also reflects adjustments for nonperformance and credit risk. We conduct our hedging activities related to foreign currency, interest rate, fuel and explosives exposures with a variety of highly-rated commercial banks and closely monitor counterparty creditworthiness. To reduce our credit exposure for these hedging activities, we seek to enter into netting agreements with counterparties that permit us to offset receivables and payables with such counterparties.

Foreign Currency Risk

We utilize currency forwards to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 4 to our consolidated financial statements. Assuming we had no hedges in place, our exposure in operating costs and expenses due to a $0.10 change in the Australian dollar/U.S. dollar exchange rate is approximately $208 million for 2011. However, taking into consideration hedges currently in place, our net exposure to the same rate change is approximately $60 million for 2011. The table at the end of Item 7A shows the notional amount of our hedge contracts as of December 31, 2010.

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. From time to time, we manage our debt to achieve a certain ratio of fixed-rate debt and variable-rate debt as a percent of net debt through the use of various hedging instruments, which are discussed in detail in Note 4 to our consolidated financial statements. As of December 31, 2010, we had $2.3 billion of fixed-rate borrowings and $0.5 billion of variable-rate borrowings outstanding and had no interest rate swaps in place. A one percentage point increase in interest rates would result in an annualized increase to interest expense of approximately $5 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 $163 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. Sales under such agreements comprised approximately 91%, 93% and 90% of our worldwide sales (by volume) for the years ended December 31, 2010, 2009 and 2008, respectively. Substantially all of our coal in the U.S is contracted in 2011 at planned production levels. We had 13 to 15 million tons remaining to be priced for 2011 in Australia at January 25, 2011.

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 cost pass-through contracts and derivatives, primarily swaps.

Notional amounts outstanding under fuel-related, derivative swap contracts are noted in the table at the end of Item 7A. We expect to consume 145 to 150 million gallons of diesel fuel in 2011. 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 $36 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 table at the end of Item 7A. We expect to consume 355,000 to 365,000 tons of explosives during 2011 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 $2 million.

Notional Amounts and Fair Value. The following summarizes our interest rate, foreign currency and commodity positions at December 31, 2010:

	Notional Amount by Year of Maturity						
	Total	**2011**	**2012**	**2013**	**2014**	**2015**	**2016 and thereafter**
Foreign Currency							
A$:US$ hedge contracts (A$ millions)	$ 4,187.5	$ 1,484.2	$ 1,355.2	$ 926.6	$ 421.5	$	$
Commodity Contracts							
Diesel fuel hedge contracts (million gallons)	191.4	89.5	76.2	25.7			
U.S. explosives hedge contracts (million MMBtu)	8.4	3.9	3.0	1.5			

	Account Classification by			
	Cash flow hedge	**Fair value hedge**	**Economic hedge**	**Fair Value Asset (Liability) (Dollars in millions)**
Foreign Currency				
A$:US$ hedge contracts (A$ millions)	$ 4,187.5	$	$	$ 640.1
Commodity Contracts				
Diesel fuel hedge contracts (million gallons)	191.4			$ 40.3
U.S. explosives hedge contracts (million MMBtu)	8.4			$ (0.1)

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, 2010, 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, 2010, and concluded that such controls and procedures are effective to provide reasonable assurance that the desired control objectives were achieved.

Table of Contents

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 three months ended December 31, 2010 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 was effective to provide reasonable assurance that the desired control objectives were achieved as of December 31, 2010.

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 28, 2011

Table of Contents

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, 2010, 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, 2010, 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, 2010 and 2009, 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, 2010 and our report dated February 28, 2011, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 28, 2011

Table of Contents

Item 9B. *Other Information.*

Mine Safety Disclosures

As discussed in Item 1. Business, our goal is to operate free of injuries, occupational illnesses, property damage and near misses. Safety is a core value that is integrated into all areas of our business. One of the ways we monitor safety performance is by incidence rate, which is tracked through our safety tracking system. We compute the incidence rate as the number of injuries (MSHA injury degree code 1 to 6) divided into employee hours worked, multiplied by 200,000 hours. Our incidence rate excludes the injuries and hours associated with office workers. The following table reflects our incidence rates and the comparable MSHA incidence rates.

	Year Ended December 31,		
	2010	**2009**	**2008**
U.S.	1.95	2.08	1.70
Australia	4.03	4.43	7.24
Total Peabody Energy Corporation	2.69	2.87	3.55
MSHA	3.86	4.14	4.41

For the U.S., the comparable MSHA incidence rate is from MSHA s Mine Injury and Worktime Operators report and represents the all incidence rate for all U.S. coal mines, excluding the impact of office workers (All Incidence Rate). The 2010 MSHA all incidence rate of 3.86 reflected above represents preliminary results as published by MSHA as of February 18, 2011.

We monitor MSHA compliance using violations per inspection day (in the U.S. only). We measure one inspection day for each visit to one of our mines by a MSHA inspector. For the years ended December 31, 2010, 2009 and 2008, our U.S. violations per inspection day were 1.25, 1.51 and 1.49, respectively.

The following disclosures are provided pursuant to the recently enacted Dodd-Frank Act, which requires certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate coal mines regulated under the Federal Mine Safety and Health Act of 1977 (the Mine Act). The disclosures reflect U.S. mining operations only as the requirements of the Dodd-Frank Act do not apply to our mines operated outside the U.S. Under the Dodd-Frank Act, the SEC is authorized to issue rules and regulations to carry out the purposes of these provisions. In December 2010, the SEC issued a proposed rule for the mine safety disclosures. As of the filing date of this report, the proposed rule was still in the comment period phase.

Mine Safety Information. Whenever MSHA believes that a violation of the Mine Act, any health or safety standard, or any regulation has occurred, it may issue a citation which describes the violation and fixes a time within which the operator must abate the violation. In some situations, such as when MSHA believes that conditions pose a hazard to miners, MSHA may issue an order removing miners from the area of the mine affected by the condition until hazards are corrected. Whenever MSHA issues a citation or order, it generally proposes a civil penalty, or fine, as a result of the violation that the operator is ordered to pay. Citations and orders can be contested and appealed, and as part of that process, are often reduced in severity and amount, and are sometimes dismissed. The number of citations, orders and proposed assessments vary depending on the size and type (underground or surface) of the mine as well as by the

MSHA inspector(s) assigned to that mine. Since MSHA is a branch of the U.S. Department of Labor, its jurisdiction applies only to our U.S. mines. While our Australian mines are not required to report safety information to MSHA, in 2008 we modified our injury reporting processes such that our Australian operations began capturing safety data using the same criteria as that of our U.S. operations. However, the safety data for our Australian mines does not include MSHA issued citations, orders and proposed assessments. As such, the mine safety disclosures below contain no information for our Australian mines.

The table that follows reflects citations and orders issued to us by MSHA during the three months and year ended December 31, 2010, as reflected in our safety tracking system. Due to timing and other factors,

Table of Contents

our data may not agree with the mine data retrieval system maintained by MSHA. The proposed assessments for the three months ended December 31, 2010 were taken from the MSHA system as of February 18, 2011.

Additional information follows about MSHA references used in the table.

Section 104 Citations: The total number of violations received from MSHA under section 104 of the Mine Act, which includes citations for health or safety standards that could significantly and substantially contribute to a serious injury if left unabated.

Section 104(b) Orders: The total number of orders issued by MSHA under section 104(b) of the Mine Act, which represents a failure to abate a citation under section 104(a) within the period of time prescribed by MSHA. This results in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.

Section 104(d) Citations and Orders: The total number of citations and orders issued by MSHA under section 104(d) of the Mine Act for unwarrantable failure to comply with mandatory health or safety standards.

Section 110(b)(2) Violations: The total number of flagrant violations issued by MSHA under section 110(b)(2) of the Mine Act.

Section 107(a) Orders: The total number of orders issued by MSHA under section 107(a) of the Mine Act for situations in which MSHA determined an imminent danger existed.

Three Months Ended December 31, 2010

Mine[1]	**Section 104 Citations**	**Section 104(b) Orders**	**Section 104(d) Citations and Orders**	**Section 104(e) Potential pattern of Violations**	**Section 110(b)(2) Violations**	**Section 107(a) Orders**	**($) Proposed MSHA Assessments (In thousands)**	**Fatalities**
Western U.S. Mining								
Caballo	1						0.1	
El Segundo	1						0.1	
Kayenta	10						14.5	
Lee Ranch	2						2.4	
North Antelope Rochelle	9						1.1	
Rawhide	5						2.0	
Twentymile (Foidel Creek)	55		1				45.9	
Midwestern U.S. Mining								
Air Quality	133	1					175.1	
Bear Run	13	1					1.7	
Francisco Underground	90	1	1				132.6	
Gateway	135		3				200.7	
Somerville Central	23						29.4	

Viking (Viking-Corning and Knot Pit)	9					12.0
Wildcat Hills Underground	82					52.2
Willow Lake (Willow Lake Portal and Central Preparation Plant)	185	2	1	1	1	347.3

62

Table of Contents

Year Ended December 31, 2010

Mine[1]	Section 104 Citations	Section 104(b) Orders	Section 104(d) Citations and Orders	Section 104(e) Potential pattern of Violations	Section 110(b)[2] Violations	Section 107(a) Orders	($) Proposed MSHA Assessments (In thousands)	Fatalities
Western U.S. Mining								
Caballo	19						8.7	
El Segundo	14						3.3	
Kayenta	66					1	68.7	
Lee Ranch	22						33.2	
North Antelope Rochelle	49						69.8	
Rawhide	12					1	13.0	
Twentymile (Foidel Creek)	262		1			1	327.7	
Midwestern U.S. Mining								
Air Quality	497	2	8				922.0	
Bear Run	27	1					4.3	
Cottage Grove (Wildcat Hills-Cottage Grove Pit)	11						3.5	
Farmersburg[2]	15						19.7	
Francisco Underground	427	2	9				586.6	
Francisco Surface[2]	17						50.1	
Gateway	481		9			1	1,172.8	
Midwest Repair Facility (Columbia Maintenance Services)	6						0.7	
Somerville Central	50						89.2	
Viking (Viking-Corning and Knot Pit)	47						55.3	
Wildcat Hills Underground	307						252.7	
Willow Lake (Willow Lake Portal and Central Preparation Plant)	904	3	17	1	1		2,213.5	1

(1) The definition of mine under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting coal, such as land, structures, facilities, equipment, machines, tools, and coal preparation facilities. Unless otherwise indicated, any of these other items associated with a single mine have been aggregated in the totals for that mine. Also, there are instances where the mine name per the MSHA system differs from the mine name utilized by us. Where applicable, we have parenthetically listed the name(s) of the mine per the MSHA system.

(2) The Francisco Surface Mine was closed in the fourth quarter of 2009 and the Farmersburg Mine was closed in the fourth quarter of 2010.

Pattern or Potential Pattern of Violations. On November 19, 2010, we received a written notice from MSHA that a potential pattern of violations exists at our Willow Lake Mine. The notification was based upon a screening by MSHA of compliance records and of accident and employment records at the mine. During the three months ended December 31, 2010, no other mines operated by us received written notice from MSHA of (a) a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal mine health or safety hazards under section 104(e) of the Mine Act or (b) the potential to have such a pattern.

Pending Legal Actions. The Federal Mine Safety and Health Review Commission (the Commission) is an independent adjudicative agency that provides administrative trial and appellate review of legal disputes arising under the Mine Act. These cases may involve, among other questions, challenges by operators to citations, orders and penalties they have received from MSHA, or complaints of discrimination by miners under Section 105 of the Mine Act. The following is a brief description of the types of legal actions that may be brought before the Commission.

Table of Contents

Contests of Citations and Orders   A contest proceeding may be filed with the Commission by operators, miners or miners   representatives to challenge the issuance of a citation or order issued by MSHA.

Contests of Proposed Penalties (Petitions for Assessment of Penalties)   A contest of a proposed penalty is an administrative proceeding before the Commission challenging a civil penalty that MSHA has proposed for the violation contained in a citation or order.

Complaints for Compensation   A complaint for compensation may be filed with the Commission by miners entitled to compensation when a mine is closed by certain withdrawal orders issued by MSHA. The purpose of the proceeding is to determine the amount of compensation, if any, due miners idled by the orders.

Complaints of Discharge, Discrimination or Interference   A discrimination proceeding is a case that involves a miner s allegation that he or she has suffered a wrong by the operator because he or she engaged in some type of activity protected under the Mine Act, such as making a safety complaint.

Temporary Reinstatement Proceedings   Temporary reinstatement proceedings involve cases in which a miner has filed a complaint with MSHA stating he or she has suffered discrimination and the miner has lost his or her position.

Emergency Response Plan (ERP) Dispute Proceedings   ERP dispute proceedings are cases brought before the Commission when an operator is issued a citation because it has not agreed to include a certain provision in its ERP.

The table that follows presents information by mine regarding pending legal actions before the Commission at December 31, 2010. Each legal action is assigned a docket number by the Commission and may have as its subject matter one or more citations, orders, penalties or complaints.

Mine[(1)]	**Legal Actions**
Western U.S. Mining	
Caballo	1
Kayenta	7
Lee Ranch	1
North Antelope Rochelle	12
Rawhide	4
Twentymile (Foidel Creek)	27
Midwestern U.S. Mining	
Air Quality	26
Cottage Grove (Wildcat Hills-Cottage Grove Pit)	2
Francisco Underground	8
Gateway	12
Somerville Central	2
Vermilion Grove	1
Viking (Viking-Corning and Knot Pit)	1
Wildcat Hills Underground	1
Willow Lake (Willow Lake Portal and Central Preparation Plant)	42

(1) The definition of mine under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting coal, such as land, structures, facilities, equipment, machines, tools and coal preparation facilities. Unless otherwise indicated, any of these other items associated with a single mine have been aggregated in the totals for that mine. Also, there are instances where the mine name per the MSHA system differs from the mine name utilized by us. Where applicable, we have parenthetically listed the name(s) of the mine per the MSHA system.

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 2011 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 2011 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 2011 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 Item 403 of Regulation S-K is included under the caption Ownership of Company Securities in our 2011 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, 2010:

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	1,437,039(1)	$ 27.61(2)	13,541,829(3)

Equity compensation plans not approved by security holders				
Total	1,437,039	$	27.61	13,541,829

(1) Includes 38,331 shares issuable pursuant to outstanding deferred stock units and 159,553 shares issuable pursuant to outstanding performance units.

(2) The weighted average exercise price shown in the table does not take into account outstanding deferred stock units or performance awards.

(3) Includes 2,310,734 shares available for issuance under our U.S. Employee Stock Purchase Plan and 976,823 shares available for issuance under our Australian Employee Stock Purchase Plan.

Table of Contents

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 2011 Proxy Statement and is incorporated herein by reference.

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 2011 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:

	Page
Report of Independent Registered Public Accounting Firm	F-1
Consolidated Statements of Operations Years Ended December 31, 2010, 2009 and 2008	F-2
Consolidated Balance Sheets December 31, 2010 and December 31, 2009	F-3
Consolidated Statements of Cash Flows Years Ended December 31, 2010, 2009 and 2008	F-4
Consolidated Statements of Changes in Stockholders Equity Years Ended December 31, 2010, 2009 and 2008	F-5
Notes to Consolidated Financial Statements	F-6

(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:

	Page
Valuation and Qualifying Accounts	F-69

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% 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.

Table of Contents

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 28, 2011

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 28, 2011
/s/ MICHAEL C. CREWS Michael C. Crews	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 28, 2011
/s/ WILLIAM A. COLEY William A. Coley	Director	February 28, 2011
/s/ WILLIAM E. JAMES William E. James	Director	February 28, 2011
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 28, 2011
/s/ M. FRANCES KEETH M. Frances Keeth	Director	February 28, 2011
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 28, 2011
/s/ ROBERT A. MALONE	Director	February 28, 2011

Robert A. Malone		
/s/ WILLIAM C. RUSNACK	Director	February 28, 2011
William C. Rusnack		
/s/ JOHN F. TURNER	Director	February 28, 2011
John F. Turner		
/s/ SANDRA VAN TREASE	Director	February 28, 2011
Sandra Van Trease		
/s/ ALAN H. WASHKOWITZ	Director	February 28, 2011
Alan H. Washkowitz		

Table of Contents

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, 2010 and 2009, 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, 2010. Our audits included the financial statement schedule listed in Item 15(a). These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Peabody Energy Corporation s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2011, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 28, 2011

See accompanying notes to consolidated financial statements

Table of Contents

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2010	2009	2008
	(Dollars in millions, except per share data)		
Revenues			
Sales	$ 6,331.3	$ 5,468.1	$ 6,004.0
Other revenues	528.7	544.3	557.0
Total revenues	6,860.0	6,012.4	6,561.0
Costs and expenses			
Operating costs and expenses	4,841.0	4,472.6	4,589.7
Depreciation, depletion and amortization	440.9	405.2	402.4
Asset retirement obligation expense	48.5	40.1	48.2
Selling and administrative expenses	232.2	203.8	197.3
Other operating (income) loss:			
Net gain on disposal or exchange of assets	(30.0)	(23.2)	(72.9)
Loss from equity affiliates	1.7	69.1	
Operating profit	1,325.7	844.8	1,396.3
Interest expense	222.1	201.2	227.0
Interest income	(9.6)	(8.1)	(10.0)
Income from continuing operations before income taxes	1,113.2	651.7	1,179.3
Income tax provision	308.1	193.8	191.4
Income from continuing operations, net of income taxes	805.1	457.9	987.9
Income (loss) from discontinued operations, net of income taxes	(2.9)	5.1	(28.8)
Net income	802.2	463.0	959.1
Less: Net income attributable to noncontrolling interests	28.2	14.8	6.2
Net income attributable to common stockholders	$ 774.0	$ 448.2	$ 952.9
Income From Continuing Operations			
Basic earnings per share	$ 2.89	$ 1.66	$ 3.63
Diluted earnings per share	$ 2.86	$ 1.64	$ 3.60
Net Income Attributable to Common Stockholders			
Basic earnings per share	$ 2.88	$ 1.68	$ 3.52
Diluted earnings per share	$ 2.85	$ 1.66	$ 3.50

Dividends declared per share	$ 0.295	$ 0.250	$ 0.240

See accompanying notes to consolidated financial statements

Table of Contents

PEABODY ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(Amounts in millions, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,295.2	$ 988.8
Accounts receivable, net of allowance for doubtful accounts of $30.3 at December 31, 2010 and $18.3 at December 31, 2009	558.2	303.0
Inventories	332.9	325.1
Assets from coal trading activities, net	192.5	276.8
Deferred income taxes	120.4	40.0
Other current assets	459.0	255.3
Total current assets	2,958.2	2,189.0
Property, plant, equipment and mine development		
Land and coal interests	7,657.0	7,557.3
Buildings and improvements	1,079.8	908.0
Machinery and equipment	1,699.3	1,391.2
Less: accumulated depreciation, depletion and amortization	(3,010.0)	(2,595.0)
Property, plant, equipment and mine development, net	7,426.1	7,261.5
Investments and other assets	978.8	504.8
Total assets	$ 11,363.1	$ 9,955.3
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 43.2	$ 14.1
Liabilities from coal trading activities, net	181.7	110.6
Accounts payable and accrued expenses	1,288.8	1,187.7
Total current liabilities	1,513.7	1,312.4
Long-term debt, less current maturities	2,706.8	2,738.2
Deferred income taxes	539.8	299.1
Asset retirement obligations	501.3	452.1
Accrued postretirement benefit costs	963.9	914.1
Other noncurrent liabilities	448.3	483.5
Total liabilities	6,673.8	6,199.4
Stockholders equity		

Preferred Stock $0.01 per share par value; 10.0 shares authorized, no shares issued or outstanding as of December 31, 2010 or December 31, 2009		
Series A Junior Participating Preferred Stock 1.5 shares authorized, no shares issued or outstanding as of December 31, 2010 or December 31, 2009		
Perpetual Preferred Stock 0.8 shares authorized, no shares issued or outstanding as of December 31, 2010 or December 31, 2009		
Series Common Stock $0.01 per share par value; 40.0 shares authorized, no shares issued or outstanding as of December 31, 2010 or December 31, 2009		
Common Stock $0.01 per share par value; 800.0 shares authorized, 279.1 shares issued and 270.2 shares outstanding as of December 31, 2010 and 276.8 shares issued and 268.2 shares outstanding as of December 31, 2009	2.8	2.8
Additional paid-in capital	2,182.0	2,067.7
Retained earnings	2,878.4	2,183.8
Accumulated other comprehensive loss	(67.9)	(183.5)
Treasury shares, at cost: 8.9 shares as of December 31, 2010 and 8.6 shares as of December 31, 2009	(334.6)	(321.1)
Peabody Energy Corporation s stockholders equity	4,660.7	3,749.7
Noncontrolling interests	28.6	6.2
Total stockholders equity	4,689.3	3,755.9
Total liabilities and stockholders equity	$ 11,363.1	$ 9,955.3

See accompanying notes to consolidated financial statements

F-3

Table of Contents

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in millions)		
Cash Flows From Operating Activities			
Net income	$ 802.2	$ 463.0	$ 959.1
(Income) loss from discontinued operations, net of income taxes	2.9	(5.1)	28.8
Income from continuing operations, net of income taxes	805.1	457.9	987.9
Adjustments to reconcile income from continuing operations, net of income taxes to net cash provided by operating activities:			
Depreciation, depletion and amortization	440.9	405.2	402.4
Deferred income taxes	71.7	131.1	(33.3)
Share-based compensation	41.1	38.8	34.9
Net gain on disposal or exchange of assets	(30.0)	(23.2)	(72.9)
Loss from equity affiliates	1.7	69.1	
Revenue recovery on coal supply agreement			(56.9)
Dividends received from equity affiliates			19.9
Changes in current assets and liabilities:			
Accounts receivable	(149.2)	101.8	(114.7)
Change in receivable from accounts receivable securitization program	(104.6)	(20.4)	
Inventories	(7.7)	(48.9)	(13.2)
Net assets from coal trading activities	(109.6)	70.9	(43.0)
Other current assets	(28.5)	(3.2)	2.3
Accounts payable and accrued expenses	223.3	(121.6)	245.7
Asset retirement obligations	32.5	27.7	32.9
Workers compensation obligations	(8.9)	3.0	10.3
Accrued postretirement benefit costs	23.1	7.2	13.6
Contributions to pension plans	(112.6)	(38.7)	(21.3)
Other, net	15.4	(0.9)	26.2
Net cash provided by continuing operations	1,103.7	1,055.8	1,420.8
Net cash used in discontinued operations	(16.6)	(5.6)	(123.0)
Net cash provided by operating activities	1,087.1	1,050.2	1,297.8
Cash Flows From Investing Activities			
Additions to property, plant, equipment and mine development	(557.0)	(260.6)	(264.1)
Investment in Prairie State Energy Campus	(76.0)	(56.8)	(40.9)
Federal coal lease expenditures		(123.6)	(178.5)
Proceeds from disposal of assets, net of notes receivable	19.2	53.9	72.8
Investments in equity affiliates and joint ventures	(18.8)	(15.0)	(2.6)
Investments in debt and equity securities	(74.6)		
Proceeds from sale of debt securities	12.4		

Other, net	(8.8)	(6.1)	(6.0)
Net cash used in continuing operations	(703.6)	(408.2)	(419.3)
Net cash provided by discontinued operations		1.7	23.9
Net cash used in investing activities	(703.6)	(406.5)	(395.4)
Cash Flows From Financing Activities			
Change in revolving line of credit			(97.7)
Proceeds from long-term debt	1,150.0		
Payments of long-term debt	(1,167.3)	(37.1)	(32.7)
Common stock repurchase			(199.8)
Dividends paid	(79.4)	(66.8)	(64.9)
Repurchase of employee common stock relinquished for tax withholding	(13.5)	(2.3)	(11.0)
Payment of debt issuance costs	(32.2)		
Excess tax benefits related to share-based compensation	51.0		
Proceeds from stock options exercised	16.4	3.6	14.1
Acquisition of noncontrolling interests (Millennium Mine)			(110.1)
Other, net	(2.1)	(2.0)	4.1
Net cash used in financing activities	(77.1)	(104.6)	(498.0)
Net change in cash and cash equivalents	306.4	539.1	404.4
Cash and cash equivalents at beginning of year	988.8	449.7	45.3
Cash and cash equivalents at end of year	$ 1,295.2	$ 988.8	$ 449.7

See accompanying notes to consolidated financial statements

Table of Contents

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, 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 tax benefit)					(217.9)		(217.9)
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
Repurchase of employee common stock relinquished for tax withholding			(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
Repurchase of employee common stock relinquished for tax withholding			(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
Comprehensive income:							
Net income				774.0		28.2	802.2
Increase in fair value of cash flow hedges (net of $129.5 tax provision)					127.5		127.5
Postretirement plans and workers compensation obligations (net of $2.1 tax benefit)					(11.9)		(11.9)
Comprehensive income				774.0	115.6	28.2	917.8
Dividends paid				(79.4)			(79.4)
Share-based compensation		41.1					41.1
Excess tax benefits related to share based compensation		51.0					51.0
Stock options exercised		16.4					16.4
Employee stock purchases		5.8					5.8
Repurchase of employee common stock relinquished for tax withholding			(13.5)				(13.5)
Distributions to noncontrolling interests						(5.8)	(5.8)
December 31, 2010	$ 2.8	$ 2,182.0	$ (334.6)	$ 2,878.4	$ (67.9)	$ 28.6	$ 4,689.3

See accompanying notes to consolidated financial statements

F-5

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies Discussion

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 coal sales of other coal producers both as principal and agent, and trades coal, freight and freight-related contracts. 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 and Accounting Standards Not Yet Implemented

In December 2010, the Financial Accounting Standards Board (FASB) issued an update to guidance on accounting for Business Combinations that clarified a public entity s disclosure requirements for pro forma presentation of revenue and earnings related to a business combination. The new guidance requires that if comparative statements are presented, the public entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the year had occurred as of the beginning of the comparable prior annual reporting period only. The guidance also requires the supplemental pro forma disclosures to include a description of the nature and amount of material nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010 (January 1, 2011 for the Company), though early adoption is permitted. The guidance, should it become applicable, will impact the Company s disclosures but it will not impact the Company s results of operations, financial condition or cash flows.

In January 2010, the FASB issued accounting guidance that requires new fair value disclosures, including significant transfers in and out of Level 1 and Level 2 fair-value measurements and a description of the reasons for the transfers. In addition, the guidance requires new disclosures regarding activity in Level 3 fair value measurements, including a gross basis reconciliation. The new disclosure requirements became effective for interim and annual periods beginning January 1, 2010, except for the disclosure of activity within Level 3 fair value measurements, which is effective for fiscal years beginning after December 15, 2010 (January 1, 2011 for the Company). While the adoption of the guidance had an impact on the Company s disclosures, it did not affect the Company s results of operations, financial condition or cash flows. Further, the adoption of the gross presentation of Level 3 activity will also impact the Company s disclosures, but will not affect its results of operations, financial condition or cash flows.

In June 2009, the FASB issued accounting guidance on consolidations which 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

involvement in variable interest entities and any associated changes in risk exposure. The guidance became effective January 1, 2010, at which time there was no impact on the Company s results of operations, financial condition or cash flows. The Company will continue monitoring and assessing its business ventures in accordance with the guidance.

In June 2009, the FASB issued accounting guidance 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 guidance, which became effective January 1, 2010, had an impact on the Company s disclosures for its accounts receivable securitization program, but did 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 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 net revenues from coal trading activities as discussed in Note 5 and coal revenues that were derived from the Company s mining operations and sold through the Company s coal trading business. Also included are revenues from contract termination or restructuring payments, royalties related to coal lease agreements, sales agency commissions, farm income, property and facility rentals and generation development activities. 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.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2010, 2009 and 2008 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 are charged to operating costs as incurred. 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 nonmonetary exchanges of reserves or businesses. The net book value of coal reserves totaled $5.0 billion as of December 31, 2010 and $5.3 billion as of December 31, 2009. These coal reserves include mineral rights for leased coal interests and advance royalties that had a net book value of $3.7 billion as of December 31, 2010 and $4.0 billion as of December 31, 2009. The remaining net book value of coal reserves of $1.3 billion at December 31, 2010 and $1.3 billion at December 31, 2009 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 $1.3 billion as of December 31, 2010 and $1.4 billion as of December 31, 2009.

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. The estimated useful lives by category of assets are as follows:

	Years
Building and improvements	10 to 20
Machinery and equipment	3 to 33
Leasehold improvements	Life of Lease

Included in machinery and equipment are certain assets that are depreciated using the straight-line method over the estimated life of the mine, which varies from one to 33 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, and the income (loss) from its equity affiliates:

	Book Value at December 31,		Income (Loss) from Equity Affiliates for the Year Ended December 31,		
	2010	2009	2010	2009	2008
	(Dollars in millions)				
Interest in Carbones del Guasare	$	$	$	$ (54.6)	$ 5.7
Other equity method investments	2.7	5.1	(1.7)	(14.5)	(5.7)
Total equity method investments	$ 2.7	$ 5.1	$ (1.7)	$ (69.1)	$

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

Accruals for other environmental matters 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. The current portion of these accruals is included in Accounts payables and accrued expenses and the long-term portion is included in Other noncurrent liabilities in the consolidated balance sheets.

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 recognizes 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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.

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 Notes 4 and 5.

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

Use of Estimates in the Preparation of the Consolidated Financial Statements

The preparation of financial statements in conformity with U.S. generally accepted accounting principles (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.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2010, 2009 or 2008.

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 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 total foreign currency remeasurement losses for the years ended December 31, 2010 and 2009 were $38.5 million and $55.4 million, respectively. The total foreign currency remeasurement gain for the year ended December 31, 2008 was $71.1 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. See Note 14 for information related to share-based compensation.

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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Discontinued operations reflect the spin off of Patriot Coal Corporation (Patriot) and other operations recently divested, as well as certain non-strategic Midwestern mining assets held for sale where the Company has committed to the divestiture of such assets.

Revenues resulting from discontinued operations (including assets held for sale) were $84.2 million, $301.5 million and $513.0 million for the years ended December 31, 2010, 2009 and 2008, respectively. Nearly all of these revenues pertain to supply agreements the Company entered into with Patriot to meet commitments under non-assignable pre-existing customer agreements sourced from Patriot mining operations. Income (loss) before income taxes from discontinued operations reflects a loss of $4.7 million and $60.6 million for the years ended December 31, 2010 and December 31, 2008, respectively, and income of $14.4 million for the year ended December 31, 2009. The income tax provision (benefit) resulting from discontinued operations reflects a benefit of $1.8 million and $31.8 million for the years ended December 31, 2010 and December 31, 2008, respectively, and a provision of $9.3 million for the year ended December 31, 2009.

Total assets related to discontinued operations were $15.7 million and $40.6 million as of December 31, 2010 and 2009, respectively. Total liabilities associated with discontinued operations were $14.8 million and $47.1 million as of December 31, 2010 and 2009, respectively.

(3) Inventories

Inventories consisted of the following:

	December 31, 2010	December 31, 2009
	(Dollars in millions)	
Materials and supplies	$ 97.1	$ 106.5
Raw coal	55.4	80.5
Saleable coal	180.4	138.1
Total	$ 332.9	$ 325.1

(4) Derivatives and Fair Value Measurements

Risk Management Non Coal Trading Activities

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. From time to time, the Company manages the interest rate risk associated with the fair value of its fixed rate borrowings 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 result

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

from market interest rate changes. From time to time, 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. As of December 31, 2010, the Company had no interest rate swaps in place.

Foreign Currency Hedges. The Company is exposed to foreign currency exchange rate risk, primarily 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. As of December 31, 2010, the Company had only forward contracts in place.

Diesel Fuel and Explosives Hedges. The Company is exposed to commodity price risk associated with diesel fuel and explosives in the U.S. and Australia. This risk is managed through the use of cost pass-through 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. In Australia, the explosives costs and a portion of the diesel fuel costs are not hedged as they are usually included in the fees paid to the Company s contract miners.

Notional Amounts and Fair Value. The following summarizes the Company s foreign currency and commodity positions at December 31, 2010:

	Notional Amount by Year of Maturity						
	Total	2011	2012	2013	2014	2015	2016 and thereafter
Foreign Currency							
A$:US$ hedge contracts (A$ millions)	$ 4,187.5	$ 1,484.2	$ 1,355.2	$ 926.6	$ 421.5	$	$
Commodity Contracts							
Diesel fuel hedge contracts (million gallons)	191.4	89.5	76.2	25.7			
U.S. explosives hedge contracts (million MMBtu)	8.4	3.9	3.0	1.5			

	Account Classification by			
	Cash flow hedge	Fair value hedge	Economic hedge	Fair Value Asset (Liability) (Dollars in millions)
Foreign Currency				
A$:US$ hedge contracts (A$ millions)	$ 4,187.5	$	$	$ 640.1

Commodity Contracts			
Diesel fuel hedge contracts (million gallons)	191.4	$	40.3
U.S. explosives hedge contracts (million MMBtu)	8.4	$	(0.1)

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.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Company s derivative positions for the hedging of future explosives purchases are based on natural gas, which is the primary price component of explosives. However, a small measure of ineffectiveness exists as the contractual purchase price includes manufacturing fees that are subject to periodic adjustments. In addition, other fees, such as transportation surcharges, can result in ineffectiveness, but have historically changed infrequently and comprise a small portion of the total explosives cost.

With respect to the interest rate swaps, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2010, 2009 or 2008.

The tables below show the classification and amounts of pre-tax gains and losses related to the Company s non-trading hedges during the years ended December 31, 2010 and 2009:

		Year Ended December 31, 2010			
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	$ (8.5)	$ 0.8	$ (0.5)	$
Diesel fuel hedge contracts:					
- Cash flow hedges	Operating costs and expenses		34.1	(27.3)	(1.1)
Explosives cash flow hedge contracts:					
- Cash flow hedges	Operating costs and expenses		(4.2)	(8.9)	
Foreign currency cash flow hedge contracts	Operating costs and expenses		622.2	188.2	

Total	$	(8.5)	$	652.9	$	151.5	$	(1.1)

(1) Amounts relate to swaps that were de-designated and terminated in conjunction with the refinancing of the Company s previous credit facility.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

		Year Ended December 31, 2009			
Financial Instrument	**Income Statement Classification Gains (Losses) - Realized**	**Gain (loss) recognized in income on non-designated derivatives[2]**	**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

[2] Amounts relate to diesel fuel and explosives hedge derivatives that were de-designated in 2009.

Based on their fair value at December 31, 2010, the amount of gains to be realized in 2011 associated with the Company s foreign currency and diesel fuel hedge programs are expected be approximately $274 million and $13 million, respectively. The losses to be realized under the explosives hedge program are expected to be less than $1 million.

The classification and amount of derivatives presented on a gross basis as of December 31, 2010 and 2009 are as follows:

Financial Instrument	Fair Value as of December 31, 2010 Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
	(Dollars in millions)			
Diesel fuel cash flow hedge contracts	$ 25.3	$ 26.9	$ 11.9	$
Explosives cash flow hedge contracts	0.5	0.1	0.1	0.6
Foreign currency cash flow hedge contracts	273.5	366.6		
Total	$ 299.3	$ 393.6	$ 12.0	$ 0.6

Financial Instrument	Fair Value as of December 31, 2009 Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
	(Dollars in millions)			
Interest rate swaps:				
- Fair value hedges	$	$ 1.5	$	$
- Cash flow hedges				9.8
Diesel fuel cash flow hedge contracts	6.7	18.0	31.3	15.6
Explosives cash flow hedge contracts	0.1		4.9	
Foreign currency cash flow hedge contracts	110.6	100.2	1.6	3.1
Total	$ 117.4	$ 119.7	$ 37.8	$ 28.5

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

After netting by counterparty where permitted, the fair values of the respective derivatives are reflected in Other current assets, Investments and other assets, Accounts payable and accrued expenses and Other noncurrent liabilities in the consolidated balance sheets.

The Company elected the trading exemption 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. See Note 5 for information related to the Company s coal trading activities.

Fair Value Measurements

Fair Value Measured on a Recurring Basis. 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 , 2010			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Investment in debt securities	$ 17.9	$	$	$ 17.9
Commodity swaps and options diesel fuel		40.3		40.3
Commodity swaps and options explosives		(0.1)		(0.1)
Foreign currency hedge contracts		640.1		640.1
Total net financial assets	$ 17.9	$ 680.3	$	$ 698.2

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Commodity swaps and options diesel fuel	$	$ (22.2)	$	$ (22.2)
Commodity swaps and options explosives		(4.8)		(4.8)
Interest rate swaps		(8.3)		(8.3)
Foreign currency hedge contracts		206.1		206.1

Total net financial assets	$	$ 170.8	$	$ 170.8

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including interest rate yield curves, exchange indices, 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:

Investment in debt securities: valued based on quoted prices in active markets (Level 1).

Commodity swaps and options diesel fuel and explosives: generally valued based on a valuation that is corroborated by the use of market-based pricing (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).

F-16

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company did not have any transfers between levels during 2010 for its non-coal trading positions. The Company s policy is to value all transfers between levels using the beginning of period valuation. This represents a change in policy from those in effect at December 31, 2009. Previously, the end of the period values were used for transfers into Level 3 and beginning of period values for transfers out of Level 3.

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, 2010 and 2009:

Cash and cash equivalents, accounts receivable, including accounts receivable within the Company s securitization program, 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.

Investments and other assets in the consolidated balance sheets includes the Company s investments in debt and equity securities related to the Company s pro-rata share of funding in the Newcastle Coal Infrastructure Group (NCIG). The investments are recorded at cost, which approximate fair value. See Note 20 for additional information related to NCIG.

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, 2010		December 31, 2009	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Dollars in millions)			
Long-term debt	$ 2,750.0	$ 2,960.0	$ 2,752.3	$ 2,828.8

Nonperformance and Credit Risk

The fair value of the Company s non-coal trading derivative assets and liabilities reflects adjustments for nonperformance and credit risk. The Company conducts its hedging activities related to foreign currency, interest rate, fuel and explosives exposures with a variety of highly-rated commercial banks and closely monitors counterparty creditworthiness. To reduce its credit exposure for these hedging activities, the Company seeks to enter into netting agreements with counterparties that permit the Company to offset asset and liability positions with such counterparties.

(5) Coal Trading

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 its derivative trading contracts that are eligible to be cleared on an exchange, the Company utilizes exchange-published settlement prices and forward curves. For other derivative 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and therefore the valuing of its market positions should the number of third-party brokers decrease or if market liquidity is reduced.

The Company elected the trading exemption 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. 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.

Trading Revenue by Type of Instrument	Year Ended December 31, 2010	2009
	(Dollars in millions)	
Commodity swaps and options	$ 23.2	$ 176.5
Physical commodity purchase / sale contracts	135.5	85.0
Total trading revenue	$ 158.7	$ 261.5

Hedge Ineffectiveness. 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, has different quality specifications, 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.

Fair Value Measurements

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

	December 31, 2010 Gross Basis	2010 Net Basis	2009 Gross Basis	2009 Net Basis
	(Dollars in millions)			
Assets from coal trading activities	$ 1,706.2	$ 192.5	$ 949.8	$ 276.8
Liabilities from coal trading activities	(1,843.5)	(181.7)	(779.3)	(110.6)
Subtotal	(137.3)	10.8	170.5	166.2
Net margin posted (held)(1)	148.1		(4.3)	

Net value of coal trading positions	$	10.8	$	10.8	$	166.2	$	166.2

(1) Represents margin posted with counterparties of $148.2 million, net of margin held from counterparties of $0.1 million at December 31, 2010; and margin held from counterparties of $22.4 million, net of margin posted with counterparties of $18.1 million at December 31, 2009.

As previously discussed in Note 4, 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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31 , 2010			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Commodity swaps and options	$ 10.7	$ (76.2)	$	$ (65.5)
Physical commodity purchase/sale contracts		57.7	18.6	76.3
Total net financial assets (liabilities)	$ 10.7	$ (18.5)	$ 18.6	$ 10.8

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Commodity swaps and options	$ (1.7)	$ 80.7	$	$ 79.0
Physical commodity purchase/sale contracts		70.2	17.0	87.2
Total net financial assets (liabilities)	$ (1.7)	$ 150.9	$ 17.0	$ 166.2

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 (NYMEX), Intercontinental Exchange indices (ICE), NOS Clearing ASA, LCH.Clearnet (formerly known as the London Clearing House), 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 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).

Physical commodity purchase/sale contracts purchases and sales at locations with significant market activity corroborated by market-based information (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 Company did not have any significant transfers between Level 1 and Level 2 during 2010. In addition, there were no significant transfers in or out of Level 3 during 2010. The Company s policy is to value all transfers between levels using the beginning of period valuation. This represents a change in policy from that in effect at December 31, 2009. Previously, the end of the period values were used for transfers into Level 3 and beginning of period values for transfers out of Level 3.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2010	2009 (Dollars in millions)	2008
Beginning of year	$ 17.0	$ 37.8	$ 128.7
Total gains or losses (realized/unrealized):			
Included in earnings	2.1	(2.9)	(9.8)
Included in other comprehensive income	(0.5)	(1.6)	3.4
Purchases, issuances and settlements	(0.1)	(20.5)	(58.8)
Net transfers in (out)	0.1	4.2	(25.7)
End of year	$ 18.6	$ 17.0	$ 37.8

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 year:

	Year Ended December 31,		
	2010	2009 (Dollars in millions)	2008
Changes in unrealized gains (losses)(1)	$ 6.7	$ 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.

The Company s trading assets and liabilities are generally made up of forward contracts, financial swaps and margin. The net fair value of coal trading positions designated as cash flow hedges of anticipated future sales was a liability of $125.4 million as of December 31, 2010 and an asset of $93.0 million as of December 31, 2009.

As of December 31, 2010, the timing of the estimated future realization of the value of the Company s trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio Total

2011	70%
2012	21%
2013	3%
2014	4%
2015	2%
	100%

At December 31, 2010, 50% of the Company s credit exposure related to coal trading activities with investment grade counterparties and 50% with non-investment grade counterparties.

Nonperformance and Credit Risk. The fair value of the Company s coal trading assets and liabilities reflects adjustments for nonperformance and credit risk. The Company s exposure is substantially with electric utilities, 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (margin), 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 asset and liability positions with such counterparties and, to the extent required, will post or receive margin amounts associated with exchange-cleared positions.

Performance Assurances and Collateral. Certain of the Company s derivative trading instruments require the parties to provide additional performance assurances whenever a material adverse event jeopardizes one party s ability to perform under the instrument. If the Company were to sustain a material adverse event (using commercially reasonable standards), the counterparties could request collateralization on derivative trading instruments in net liability positions which, based on an aggregate fair value at December 31, 2010 and 2009, would have amounted to collateral postings of approximately $160 million and $84 million, respectively, to its counterparties. As of December 31, 2010, $5.8 million of collateral was posted to counterparties for such positions while zero was posted at December 31, 2009 (reflected in Liabilities from coal trading activities, net).

Certain of the Company s other derivative trading 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 derivative trading instruments typically require additional collateralization, which is commensurate with the severity of the credit downgrade. If a credit downgrade were to have occurred below contractually specified levels, the Company s additional collateral requirement owed to its counterparties would have been zero at December 31, 2010 and approximately $16 million at December 31, 2009 based on the aggregate fair value of all derivative trading instruments with such features that are in a net liability position. As of December 31, 2009, the Company posted $0.8 million for such instruments in a net liability position. As of December 31, 2010, $5.0 million of margin was posted with a counterparty due to timing and market fluctuations (reflected in Liabilities from coal trading activities, net).

The Company is required to post collateral on positions that are in a net liability position with an exchange, known as variation margin, which was $137.4 million as of December 31, 2010 and $18.1 million as of December 31, 2009 (reflected in Liabilities from coal trading activities, net).

In addition, the Company is required by the exchange to post certain additional collateral, known as initial margin, which represents an estimate of potential future adverse price movements across the Company s portfolio under normal market conditions. As of December 31, 2010 and 2009, the Company had posted initial margin of $39.5 million and $29.7 million, respectively (reflected in Other current assets). In addition, the Company posted $4.4 million and $5.5 million of margin in excess of the exchange-required variation and initial margin discussed above as of December 31, 2010 and 2009, respectively (also reflected in Other current assets).

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) Income Taxes

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

	Year Ended December 31, 2010	2009	2008
	(Dollars in millions)		
U.S.	$ 535.5	$ 281.4	$ 185.2
Non U.S.	577.7	370.3	994.1
Total	$ 1,113.2	$ 651.7	$ 1,179.3

Total income tax provision consisted of the following:

	Year Ended December 31, 2010	2009	2008
	(Dollars in millions)		
Current:			
U.S. federal	$ 113.9	$ (0.7)	$
Non U.S.	70.5	61.7	224.7
State	1.0	1.7	
Total current	185.4	62.7	224.7
Deferred:			
U.S. federal	47.9	56.0	47.1
Non U.S.	69.1	74.4	(81.7)
State	5.7	0.7	1.3
Total deferred	122.7	131.1	(33.3)
Total provision	$ 308.1	$ 193.8	$ 191.4

The following is a reconciliation of the expected statutory federal income tax provision to the Company s actual income tax provision:

	Year Ended December 31, 2010	2009	2008

	(Dollars in millions)		
Expected income tax provision at federal statutory rate	$ 389.6	$ 228.1	$ 412.7
Excess depletion	(53.5)	(44.0)	(40.1)
Foreign earnings provision differential	(121.4)	(83.6)	(119.7)
Foreign earnings repatriation	84.5		
Remeasurement of foreign income tax accounts	47.6	74.4	(65.2)
State income taxes, net of U.S. federal tax benefit	(4.8)	3.4	(1.6)
General business tax credits	(17.0)	(12.2)	(12.6)
Changes in valuation allowance	(28.7)	17.3	(44.2)
Changes in tax reserves		5.9	34.4
Other, net	11.8	4.5	27.7
Total provision	$ 308.1	$ 193.8	$ 191.4

Table of Contents

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, 2010	December 31, 2009
	(Dollars in millions)	
Deferred tax assets:		
Tax credits and loss carryforwards	$ 425.2	$ 557.1
Postretirement benefit obligations	427.7	474.7
Intangible tax asset and purchased contract rights	15.1	30.9
Accrued reclamation and mine closing liabilities	97.8	57.0
Accrued long-term workers compensation liabilities	15.5	23.1
Employee benefits	53.5	80.3
Hedge activities	30.6	
Financial guarantee	18.8	20.1
Others	45.4	39.5
Total gross deferred tax assets	1,129.6	1,282.7
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	1,241.5	1,221.0
Unamortized discount on Convertible Junior Subordinated Debentures	135.5	139.6
Hedge activities		29.2
Investments and other assets	107.0	64.8
Total gross deferred tax liabilities	1,484.0	1,454.6
Valuation allowance	(65.0)	(87.2)
Net deferred tax liability	$ (419.4)	$ (259.1)
Deferred taxes are classified as follows:		
Current deferred income taxes	$ 120.4	$ 40.0
Noncurrent deferred income taxes	(539.8)	(299.1)
Net deferred tax liability	$ (419.4)	$ (259.1)

The Company s tax credits and loss carryforwards included alternative minimum tax (AMT), foreign tax and general business credits of $317.0 million, state net operating loss (NOL) carryforwards of $23.8 million and foreign loss carryforwards of $84.4 million as of December 31, 2010. The AMT credits and foreign NOL and capital loss carryforwards have no expiration date. The foreign tax and general business credits begin to expire in 2020 and 2027, respectively. The state NOL carryforwards begin to expire in the year 2011. In assessing the near term use of NOLs and tax credits and corresponding valuation allowance adjustments, the Company evaluated the overall deferred tax position, available tax strategies and future taxable income. The $28.7 million change in the valuation allowance due to the 2010 assessment included a $48.8 million decrease on AMT credits, an $11.7 million increase on state NOLs and an $8.4 million increase on foreign deferred assets. The remaining valuation allowance at December 31, 2010 of $65.0 million represents a reserve for state NOLs and certain foreign deferred tax assets.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Unrecognized Tax Benefits

The total amount of the net unrecognized tax benefits was $107.9 million ($111.0 million gross) at December 31, 2010 and was $109.2 million ($113.2 million gross) at December 31, 2009. The amount of the Company s gross unrecognized tax benefits has decreased by $2.2 million since January 1, 2010 primarily as a result of the Company s Internal Revenue Service (IRS) audit for the 2005 and 2006 tax years. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits is as follows (dollars in millions):

	Year Ended December 31,		
	2010	**2009**	**2008**
Balance at beginning of period	$ 113.2	$ 186.3	$ 152.6
Additions for current year tax positions	3.4	2.7	30.3
Additions for prior year positions	13.8	15.7	3.4
Reductions for settlements with tax authorities	(19.4)	(88.5)	
Reductions for expirations of statute of limitations		(3.0)	
Balance at end of period	$ 111.0	$ 113.2	$ 186.3

The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate is $107.9 million at December 31, 2010 and $109.2 million at December 31, 2009. The Company does not expect any significant changes to its net unrecognized tax benefits within 12 months of this reporting date.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in its income tax provision. The Company has recognized $8.2 million of interest for the year ended December 31, 2010. The Company had $14.6 million and $6.4 million of accrued interest related to uncertain tax positions at December 31, 2010 and 2009, respectively. The Company has considered the application of penalties on its unrecognized tax benefits and determined, based upon several factors, that no accrual of penalties is required.

Tax Returns Subject to Examination

The Company s federal income tax returns are under examination by the IRS for the 2006 through 2008 income tax years. The Company and the IRS did not reach an agreement on the adjustment of interest income accrued by a foreign subsidiary through the alternative dispute resolution program (Fast Track Settlement) for the 2006 federal income tax year. The Company and the IRS are proceeding with the formal IRS appeals process to resolve the remaining issue, which could take one to two 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 NOL carryforwards are reduced. The IRS began an examination of the Company s federal income tax returns for the 2007 and 2008 income tax years during 2010. Notwithstanding these audit cycles, the years 1999-2001, 2003 through 2004 and 2009 remain potentially subject to examination due to NOL carryforwards. The Company s state income tax returns for the tax years 1996 and beyond remain potentially subject to examination by various state taxing authorities due to NOL carryforwards. In December 2010, the Australian Tax Office began an examination of the Company s Australian income tax returns for the tax years 2004 through 2009.

Foreign Earnings

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was $1.1 billion at December 31, 2010 and $1.4 billion at December 31, 2009. During 2010, the Company recorded tax expense of $84.5 million related to the repatriation of certain earnings of non-U.S. subsidiaries. The Company has not provided deferred taxes on foreign earnings of $1.1 billion for 2010 and $1.3 billion for 2009 because

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

such earnings are considered 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 statements of operations of up to $382.0 million could occur.

Tax Payments

The following table summarizes the Company s tax payments:

	Year Ended December 31, 2010	2009	2008
	(Dollars in millions)		
U.S. federal	$ 65.0	$	$
U.S. state and local	0.4	0.9	
Non U.S.	83.0	169.7	65.8
Total tax payments	$ 148.4	$ 170.6	$ 65.8

(7) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31, 2010	2009
	(Dollars in millions)	
Trade accounts payable	$ 467.1	$ 387.6
Other accrued expenses	193.3	160.0
Accrued taxes other than income	185.4	172.3
Accrued payroll and related benefits	155.7	135.0
Accrued health care	85.9	78.7
Accrued royalties	74.7	51.1
Income taxes payable	59.6	80.7
Accrued interest	30.5	31.7
Workers compensation obligations	14.6	8.7
Accrued environmental	6.3	7.9
Other accrued benefits	4.2	4.0
Commodity hedge contracts	2.9	29.4
Liabilities associated with discontinued operations	8.6	40.6
Total accounts payable and accrued expenses	$ 1,288.8	$ 1,187.7

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(8) Long-Term Debt

The Company s total indebtedness as of December 31, 2010 and 2009 consisted of the following:

	December 31, 2010	December 31, 2009
	(Dollars in millions)	
Term Loan	$ 493.8	$ 490.3
6.875% Senior Notes due March 2013		650.0
5.875% Senior Notes due April 2016	218.1	218.1
7.375% Senior Notes due November 2016	650.0	650.0
6.5% Senior Notes due September 2020	650.0	
7.875% Senior Notes due November 2026	247.2	247.1
6.34% Series B Bonds due December 2014	12.0	15.0
6.84% Series C Bonds due December 2016	33.0	33.0
Convertible Junior Subordinated Debentures due 2066	373.3	371.5
Capital lease obligations	69.6	67.5
Fair value hedge adjustment	2.2	8.4
Other	0.8	1.4
Total	$ 2,750.0	$ 2,752.3

Credit Facility

On June 18, 2010, the Company entered into an unsecured credit agreement (the Credit Agreement) which established a $2.0 billion credit facility (the Credit Facility) and replaced the Company s third amended and restated credit agreement dated as of September 15, 2006. The Credit Agreement provides for a $1.5 billion revolving credit facility (the Revolver) and a $500.0 million term loan facility (the Term Loan). The Company has the option to request an increase in the capacity of the Credit Facility, provided the aggregate increase for the Revolver and Term Loan does not exceed $250.0 million, the minimum amount of the increase is $25.0 million, and certain other conditions are met under the Credit Agreement. The Revolver also includes a swingline sub-facility under which up to $50.0 million is available for same-day borrowings. The Revolver commitments and the Term Loan under the Credit Facility will mature on June 18, 2015.

The Revolver replaced the Company s previous $1.8 billion revolving credit facility and the Term Loan replaced the Company s previous term loan facility (the previous term loan had a balance of $490.3 million at the time of replacement and at December 31, 2009). The Company recorded $21.9 million in deferred financing costs, which are being amortized to interest expense over the five-year term of the Credit Facility. The Company also recorded refinancing charges of $9.3 million, which was recorded in Interest expense in the consolidated statements of operations. The $500.0 million of proceeds from the Term Loan was used to repay the balance due on the Company s previous term loan facility.

All borrowings under the Credit Agreement (other than swingline borrowings and borrowings denominated in currencies other than U.S. dollars) bear interest, at the Company s option, at either a base rate or a eurocurrency rate , as defined in the Credit Agreement, plus in each case, a rate adjustment based on the Company s leverage ratio, as defined in the Credit Agreement, ranging from 2.50% to 1.25% per year for borrowings bearing interest at the base rate and from 3.50% to 2.25% per year for borrowings bearing interest at the eurocurrency rate (such rate added to the eurocurrency rate, the Eurocurrency Margin). Swingline borrowings bear interest at a BBA LIBOR rate equal to the rate at which deposits in U.S. dollars for a one month term are offered in the interbank eurodollar market, as determined by the administrative

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

agent, plus the Eurocurrency Margin. Borrowings denominated in currencies other than U.S. dollars will bear interest at the eurocurrency rate plus the Eurocurrency Margin.

The Company pays a usage-dependent commitment fee under the Revolver, which is dependent upon the Company s leverage ratio, as defined in the Credit Agreement, and ranges from 0.500% to 0.375% of the available unused commitment. Swingline loans are not considered usage of the revolving credit facility for purposes of calculating the commitment fee. The fee accrues quarterly in arrears.

In addition, the Company pays a letter of credit fee calculated at a rate dependent on the Company s leverage ratio, as defined in the Credit Agreement, ranging from 3.50% to 2.25% per year of the undrawn amount of each letter of credit and a fronting fee equal to 0.125% per year of the face amount of each letter of credit. These fees are payable quarterly in arrears.

The $500.0 million Term Loan is subject to quarterly repayment of 1.25% per quarter commencing on December 31, 2010, with the final payment of all amounts outstanding (including accrued interest) being due on June 18, 2015.

Under the Credit Agreement, the Company must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio. The Credit Agreement also includes various affirmative and negative covenants that place limitations on the Company s ability to, among other things, incur debt; make loans, investments, advances and acquisitions; sell assets; make redemptions and repurchase of capital stock; engage in mergers or consolidations; engage in affiliate transactions; and restrict distributions from subsidiaries. When in compliance with the financial covenants and customary default provisions, the Company is not restricted in its ability to pay dividends, sell assets and make redemptions or repurchase capital stock provided that the Company may only redeem and repurchase capital stock with the proceeds received from the concurrent issue of capital stock or indebtedness permitted under the Credit Agreement.

Nearly all of the Company s direct and indirect domestic subsidiaries guarantee all loans under the Credit Agreement. Certain of the Company s foreign subsidiaries also, to the extent permitted by applicable law and existing contractual obligations, would be guarantors of loans made to one of the Company s Dutch subsidiaries.

As of December 31, 2010, the Company had no borrowings on the Revolver, but had $67.6 million of letters of credit outstanding. The remaining capacity on the Revolver at December 31, 2010 was $1.4 billion.

The interest rate payable on the Revolver and the Term Loan was LIBOR plus 2.25%, or 2.51%, at December 31, 2010.

6.5% Senior Notes

On August 25, 2010, the Company completed a $650.0 million offering of 6.5% 10-year Senior Notes due September 2020 (the Notes). The Notes are senior unsecured obligations and rank senior in right of payment to any subordinated indebtedness; equally in right of payment with any senior indebtedness; would be effectively junior in right of payment to the Company s 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 its subsidiaries that do not guarantee the Notes. Interest payments are scheduled to occur on March 15 and September 15 of each year, commencing on March 15, 2011.

The Notes are jointly and severally guaranteed by nearly all of the Company s domestic subsidiaries, 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 and any accrued unpaid interest to the redemption date.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company used the net proceeds of $641.9 million from the issuance of the Notes, after deducting underwriting discounts and expenses, and cash on hand to extinguish its previously outstanding $650.0 million aggregate principal 6.875% Senior Notes formerly due in March 2013 (the 2013 Notes). All of the 2013 Notes were either tendered or redeemed during 2010. The Company recognized debt extinguishment costs of $8.4 million, which was recorded in Interest expense in the consolidated statements of operations. The issuance of the Notes and the extinguishment of the 2013 Notes allowed the Company to extend the maturity of its senior indebtedness and lower the coupon rate.

6.875% Senior Notes

The notes, which were tendered or redeemed during 2010 and are no longer outstanding, were senior unsecured obligations of the Company and ranked equally with all of the Company s other senior unsecured indebtedness. Interest payments were scheduled to occur on March 15 and September 15 of each year. The notes were guaranteed by the Company s Subsidiary Guarantors as defined in the note 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.

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 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.

Series Bonds

The Series Bonds were assumed as part of the Excel Coal Limited 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 in the consolidated statements of operations. 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.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Convertible Junior Subordinated Debentures

As of December 31, 2010, 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 $81.64 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 13) 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, the conversion rate was adjusted. The conversion rate has also been adjusted when there has been a change in the Company s dividend distribution rate. The current conversion rate is 17.1493 shares of common stock per $1,000 principal amount of Debentures effective February 7, 2011. This adjusted conversion rate represents a conversion price of $58.31.

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 (currently $75.80 per share). 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.

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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

The Company 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,	
	2010	2009
	(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	(359.2)	(361.0)
Net carrying amount	$ 373.3	$ 371.5

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

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in millions)		
Effective interest rate	4.9%	4.9%	4.9%
Interest expense contractual interest coupon	$ 34.8	$ 34.8	$ 34.5
Interest expense amortization of debt discount	1.8	1.6	1.5

The remaining period over which the discount will be amortized is 31 years as of December 31, 2010.

Interest Rate Swaps

As of December 31, 2010, the Company had no interest rate swaps in place. At December 31, 2009, there was an unrealized loss of $9.8 million related to a cash flow hedge then in place. The swap was cancelled in 2010 in connection with the refinancing of the Credit Facility as discussed above. The unrealized loss was recorded in Interest expense in the consolidated statements of operations at the time of cancellation.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2009, there was a net unrealized gain of $1.5 million on two fair value hedges then in place. The swaps were cancelled in 2010 in connection with the extinguishment of the 2013 Notes as discussed above. Additionally, at December 31, 2009 there was a fair value hedge adjustment of $3.5 million on the 2013 Notes. These net unrealized gains were reflected as a reduction in Interest expense in the consolidated statements of operations at the time of extinguishment.

The fair value hedge adjustment, which represents the unamortized portion of terminated fair value hedges ($2.2 million and $8.4 million at December 31, 2010 and 2009, respectively), is reflected as an adjustment to the carrying value of the related debt.

Because the critical terms of the swaps and the respective debt instruments they hedged coincided, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2010, 2009, or 2008.

Capital Lease Obligations

Capital lease obligations are for mining equipment (see Note 9 for additional information).

Debt Maturities, Interest Paid, and Financing Costs

The aggregate amounts of long-term debt maturities (excluding unamortized debt discounts) subsequent to December 31, 2010, including capital lease obligations, were as follows:

Year of Maturity	**(Dollars in millions)**	
2011	$	43.2
2012		50.2
2013		58.8
2014		50.0
2015		400.4
2016 and thereafter		2,147.4
Total	$	2,750.0

Interest paid on long-term debt was $197.9 million, $201.6 million and $226.0 million for the years ended December 31, 2010, 2009 and 2008, 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, 2010 was $52.0 million, of which $35.5 million will be amortized to interest expense over the next five years.

(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 $181.7 million, $127.8 million and $121.3 million for the years ended December 31, 2010, 2009 and 2008, respectively. The gross value of property, plant, equipment and mine development assets under capital leases was $109.5 million and $98.4 million as of December 31, 2010 and 2009, respectively, related primarily to the leasing of mining equipment. The accumulated depreciation for these items was $39.5 million and $31.0 million at December 31, 2010 and 2009, 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

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

mined during the year. Total royalty expense was $548.7 million, $439.4 million and $506.4 million for the years ended December 31, 2010, 2009 and 2008, 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 a majority of the coal it mines in 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 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, by including the lease as a part of a logical mining unit with other leases upon which development has occurred, or by paying advance royalty in lieu of continued operations. 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 executed under leases or licenses granted by state governments. Mining leases are typically for an initial term of up to 21 years (but which may be renewed) and contain conditions relating to such matters as minimum annual expenditures, restoration and rehabilitation. Royalties are paid to the state government as a percentage of the sales price. Generally landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by state governments. Compensation is payable to landowners for the loss of access to the land where the landowner retains the surface rights, and the amount and type of compensation can be determined by agreement or arbitration as provided in the mining law. Surface rights are typically acquired directly from landowners by mutual agreement.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Future minimum lease and royalty payments as of December 31, 2010 are as follows:

Year Ending December 31,	Capital Leases	Operating Leases	Coal Lease and Royalty Obligations
		(Dollars in millions)	
2011	$ 17.0	$ 95.6	$ 7.2
2012	17.0	78.7	6.9
2013	25.1	68.5	7.4
2014	15.5	59.0	6.2
2015		47.1	4.0
2016 and thereafter		106.9	30.3
Total minimum lease payments	$ 74.6	$ 455.8	$ 62.0
Less interest	5.0		
Present value of minimum capital lease payments	$ 69.6		

As of December 31, 2010, certain of the Company s lease obligations were secured by outstanding surety bonds totaling $110.3 million.

(10) Asset Retirement Obligations

Reconciliations of the Company s ARO liability are as follows:

	December 31, 2010	December 31, 2009
	(Dollars in millions)	
Balance at beginning of year	$ 452.1	$ 418.7
Liabilities incurred or acquired	8.2	0.4
Liabilities settled or disposed	(7.9)	(8.1)
Accretion expense	26.7	24.0
Revisions to estimates	22.2	17.1
Balance at end of year	$ 501.3	$ 452.1
Balance at end of year active locations	$ 465.4	$ 422.0

Balance at end of year	closed or inactive locations	$ 35.9	$ 30.1

The credit-adjusted, risk-free interest rates were 6.37%, 7.92%, and 7.91% at December 31, 2010, 2009 and 2008, respectively.

As of December 31, 2010 and 2009, the Company had $704.4 million and $772.3 million, respectively, in surety bonds and bank guarantees outstanding to secure reclamation obligations or activities. The amount of reclamation self-bonding in certain states in which the Company qualifies was $920.3 million and $821.9 million as of December 31, 2010 and 2009, respectively. Additionally, the Company had $0.1 million and $34.9 million of letters of credit in support of reclamation obligations or activities as of December 31, 2010 and 2009, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) 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,		
	2010	2009	2008
		(Dollars in millions)	
Service cost for benefits earned	$ 12.9	$ 10.5	$ 10.1
Interest cost on accumulated postretirement benefit obligation	58.2	55.2	54.0
Amortization of prior service cost	2.6	1.5	0.4
Amortization of actuarial loss	24.9	14.5	17.3
Net periodic postretirement benefit cost	$ 98.6	$ 81.7	$ 81.8

The following includes amounts recognized in accumulated other comprehensive loss:

	Year Ended December 31,		
	2010	2009	2008
		(Dollars in millions)	
Net actuarial (gain) loss arising during year	$ 45.3	$ 165.2	$ (18.3)
Prior service cost arising during year	7.9	(10.5)	
Amortization:			
Actuarial loss	(24.9)	(14.5)	(17.3)
Prior service cost	(2.6)	(1.5)	(0.4)
Total recognized in other comprehensive loss	25.7	138.7	(36.0)
Net periodic postretirement benefit cost	98.6	81.7	81.8
Total recognized in net periodic postretirement benefit cost and other comprehensive loss	$ 124.3	$ 220.4	$ 45.8

The Company amortizes actuarial gain and loss using a 0% corridor with an amortization period that covers the average remaining service period of active employees (11.93 years and 10.92 years at January 1, 2010 and 2009, respectively). The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive loss into net periodic postretirement benefit cost during the year ended December 31, 2011 are $26.9 million and $2.8 million, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2010	December 31, 2009
	(Dollars in millions)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of period	$ 982.2	$ 833.4
Service cost	12.9	10.5
Interest cost	58.2	55.2
Participant contributions	2.1	1.2
Plan amendments[1]	7.9	(10.5)
Benefits paid	(77.4)	(72.8)
Actuarial loss	45.3	165.2
Accumulated postretirement benefit obligation at end of period	1,031.2	982.2
Change in plan assets:		
Fair value of plan assets at beginning of period		
Employer contributions	75.3	71.6
Participant contributions	2.1	1.2
Benefits paid and administrative fees (net of Medicare Part D reimbursements)	(77.4)	(72.8)
Fair value of plan assets at end of period		
Funded status at end of year	(1,031.2)	(982.2)
Less current portion (included in Accounts payable and accrued expenses)	67.3	68.1
Noncurrent obligation (included in Accrued postretirement benefit costs)	$ (963.9)	$ (914.1)

(1) Effective January 1, 2011, certain plans were modified to ensure consistency of benefits across the Company, the impact of which is reflected in the December 31, 2010 figures above. Effective January 1, 2010, the benefits provided to certain salaried retirees were capped at a fixed level, which resulted in a decrease to the retiree health care liability of $7.3 million, the impact of which is reflected in the December 31, 2009 figures above. The Company began 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,

	2010	**2009**
Discount rate	5.81%	6.14%
Rate of compensation increase	3.50%	3.50%
Measurement date	December 31, 2010	December 31, 2009

Table of Contents

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, 2010	2009	2008
Discount rate	6.14%	6.85%	6.60%
Rate of compensation increase	3.50%	3.50%	3.50%
Measurement date	December 31, 2009	December 31, 2008	December 31, 2007

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

	Year Ended December 31, 2010	2009
Health care cost trend rate assumed for next year	9.00%	7.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2017	2016

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	$ 7.8	$ (6.6)
Effect on total postretirement benefit obligation	$ 112.5	$ (94.4)

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)
2011	$ 67.3
2012	68.8
2013	72.6
2014	74.6
2015	76.5
Years 2016-2020	402.2

(12) 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 United Mine Workers of America (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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effective May 31, 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.

Net periodic pension cost included the following components:

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in millions)		
Service cost for benefits earned	$ 1.5	$ 1.4	$ 2.0
Interest cost on projected benefit obligation	50.5	51.3	51.0
Expected return on plan assets	(58.3)	(60.9)	(60.6)
Amortization of prior service cost	1.4	1.4	1.3
Amortization of actuarial (gains) losses	21.9	1.9	(0.5)
Net periodic pension costs	17.0	(4.9)	(6.8)
Curtailment gain			(0.6)
Total net periodic pension (benefit) cost	$ 17.0	$ (4.9)	$ (7.4)

The following includes amounts recognized in accumulated other comprehensive loss:

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in millions)		
Net actuarial loss arising during year	$ 13.1	$ 46.1	$ 199.2
Amortization:			
Actuarial gain (loss)	(21.9)	(1.9)	0.5
Prior service cost	(1.4)	(1.4)	(0.7)
Total recognized in other comprehensive loss	(10.2)	42.8	199.0
Net periodic pension (benefit) cost	17.0	(4.9)	(6.8)
Total recognized in net periodic pension cost and other comprehensive loss	$ 6.8	$ 37.9	$ 192.2

The Company amortizes actuarial gain and loss 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 cost during the year ended December 31, 2011 are $30.1 million and $1.0 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, 2010	December 31, 2009
	(Dollars in millions)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$ 844.9	$ 768.6
Service cost	1.5	1.4
Interest cost	50.5	51.3
Benefits paid	(50.4)	(48.3)
Actuarial loss	34.5	71.9
Projected benefit obligation at end of period	881.0	844.9
Change in plan assets:		
Fair value of plan assets at beginning of period	629.6	552.6
Actual return on plan assets	79.8	86.6
Employer contributions	112.6	38.7
Benefits paid	(50.4)	(48.3)
Fair value of plan assets at end of period	771.6	629.6
Funded status at end of year	$ (109.4)	$ (215.3)
Amounts recognized in the consolidated balance sheets:		
Current obligation (included in Accounts payable and accrued expenses)	$ (1.8)	$ (1.8)
Noncurrent obligation (included in Other noncurrent liabilities)	(107.6)	(213.5)
Net amount recognized	$ (109.4)	$ (215.3)

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

	Year Ended December 31, 2010	Year Ended December 31, 2009
Discount rate	5.84%	6.19%
Rate of compensation increase	N/A	N/A
Measurement date	December 31, 2010	December 31, 2009

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

	Year Ended December 31,		
	2010	2009	2008
Discount rate	6.19%	6.90%	6.75%
Expected long-term return on plan assets	8.25%	8.75%	8.75%
Measurement date	December 31, 2010	December 31, 2009	December 31, 2008

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. 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2010 and 2009. The accumulated benefit obligation for all pension plans was $881.0 million and $844.9 million as of December 31, 2010 and 2009, 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.

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 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. U.S. equity securities are not subject to liquidity redemption restrictions.

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 are 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

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

on a national securities exchange. Redemptions of the common/collective trust and 103-12 investment entity can only occur as of the last business day of the month with a notification period of six business days and three business days before the end of the month, respectively.

Debt securities. Investment vehicles include U.S. government and agency securities and various institutional mutual funds that hold mortgage-backed debt securities, international debt securities and corporate debt securities. Institutional mutual funds are invested in various diversified portfolios of fixed-income instruments, and the NAV for each institutional mutual fund is calculated daily in actively traded markets by an independent custodian for the investment manager. The U.S. government and agency securities are classified within the Level 1 valuation hierarchy since fair value is based on public price quotations in active markets. The institutional mutual funds are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the institutional mutual funds are not publicly traded on a national securities exchange. Debt securities are not subject to liquidity redemption restrictions.

Short-term investments. Investment vehicles primarily include institutional mutual funds. Short-term investments include a diversified portfolio of liquid, short-term instruments of varying maturities. The institutional mutual funds are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the institutional mutual funds are not publicly traded on a national securities exchange.

Interests in real estate. Investments in real estate represent interests in several limited partnerships, which invest in various real estate 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 methodologies used for valuing investments are not necessarily an indication of the risk associated with investing in those investments.

The following tables present the fair value of assets in the Master Trust by asset category and by fair value hierarchy:

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
U.S. equity securities	$ 82.6	$ 250.5	$	$ 333.1
International equity securities		118.9		118.9
Mortgage-backed debt securities		108.2		108.2
U.S. debt securities	0.6	60.2		60.8

International debt securities		25.7		25.7
Corporate debt securities		46.1		46.1
Short-term investments		31.1		31.1
Interests in real estate			47.7	47.7
Total assets at fair value	$ 83.2	$ 640.7	$ 47.7	$ 771.6

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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

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

	Year Ended December 31,	
Interests in Real Estate	**2010**	**2009**
	(Dollars in millions)	
Beginning of year	$ 47.4	$ 62.2
Assets held at the reporting date:		
Realized loss	(0.1)	(0.8)
Unrealized gain (loss)	1.3	(19.3)
Purchases, sales and settlements, net	(0.9)	5.3
End of year	$ 47.7	$ 47.4

Contributions

Annual contributions to the Plans are made as recommended 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 required by the Pension Protection Act of 2006 (the Pension Protection Act) increased the long-term funding targets for single employer pension plans from 90% to 100%. The Pension Protection Act also introduced benefit restriction and at-risk penalties for plans that fail to meet certain funded status thresholds (generally 80%). As of December 31, 2010, the Company s qualified plans are expected to be at or above these Pension Protection Act thresholds, and therefore, avoid benefit restrictions and at-risk penalties for 2011. The Company does not anticipate any contributions to the qualified plans during 2011.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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)
2011	$ 55.7
2012	57.0
2013	58.5
2014	60.6
2015	62.7
Years 2016-2020	330.7

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 $51.3 million, $47.9 million and $50.5 million for the years ended December 31, 2010, 2009 and 2008, respectively. A performance contribution feature allows for additional contributions from the Company based upon meeting specified Company performance targets. Performance contributions related to the years ended December 31, 2010, 2009 and 2008 were $20.6 million, $20.3 million and $18.7 million, respectively.

(13) 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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes common stock activity January 1, 2008 to December 31, 2010:

	2010	2009	2008
Shares outstanding at the beginning of the year	268,203,815	266,644,979	270,066,621
Stock options exercised	1,529,501	463,490	1,388,174
Stock grants to employees	585,897	794,213	788,895
Employee stock purchases	179,611	374,548	119,737
Stock grants to non-employee directors	5,740	4,788	2,870
Shares repurchased			(5,524,574)
Shares relinquished	(268,308)	(78,203)	(196,744)
Shares outstanding at the end of the year	270,236,256	268,203,815	266,644,979

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, both with a $0.01 per share par value. 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, 2010.

Perpetual Preferred Stock

As discussed in Note 8, the Company had $732.5 million aggregate principal amount of Debentures outstanding as of December 31, 2010. 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, 2010.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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, 2010.

Treasury Stock

Share repurchase program. 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, 2010, the Company made repurchases under the program of 7.7 million shares at a cost of $299.6 million ($199.8 million in 2008 and $99.8 million in 2006), leaving $700.4 million available for share repurchase under the program.

Shares relinquished. During the year ended December 31, 2010, the Company received 268,308 shares of common stock to pay estimated taxes as consideration for 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.

(14) Share-Based Compensation

The Company has 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 24.8 million shares of the Company s common stock available for grant, with 10.3 million shares available for grant as of December 31, 2010. 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 Australian employees.

Share-Based Compensation Expense and Cash Flows

The Company s share-based compensation expense is recorded in Selling and administrative expenses in the consolidated statements of operations. The cash received by the Company upon the exercise of stock

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

options and when employees purchase stock under the employee stock purchase plans is reflected as a financing activity in the consolidated statements of cash flows. Share-based compensation expense and cash flow amounts were as follows:

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in millions)		
Share-based compensation expense	$ 41.1	$ 38.8	$ 34.9
Tax benefit	15.4	15.0	13.5
Share-based compensation expense, net of tax benefit	25.7	23.8	21.4
Cash received upon the exercise of stock options and from employee stock purchases	22.2	8.7	19.3
Excess tax benefits related to share-based compensation	51.0		

As of December 31, 2010, the total unrecognized compensation cost related to nonvested awards was $23.0 million, net of taxes, which is expected to be recognized over 3.5 years with a weighted-average period of 0.8 years.

Deferred Stock Units

In 2010, 2009 and 2008, the Company granted deferred stock units to each of its non-employee directors. The fair value of these units is equal to the market price of the Company s common stock at the date of grant. These deferred stock units generally vest after one year and are settled in common stock on the specified distribution date elected by each non-employee director.

Restricted Stock Awards

The primary share-based compensation tool used by the Company for its employee base is through awards of restricted stock. The majority of restricted stock awards are typically granted in January of each year with a lesser portion granted in the first month of the subsequent three quarters. Awards 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, net of estimated forfeitures.

A summary of restricted stock award activity is as follows:

	Year Ended December 31, 2010	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2009	2,144,865	$ 35.51
Granted	493,360	47.18
Vested	(643,828)	31.86

Forfeited	(100,098)		39.40
Nonvested at December 31, 2010	1,894,299	$	39.32

The total fair value of restricted stock awards granted during the years ended December 31, 2010, 2009 and 2008, was $23.3 million, $23.1 million and $20.4 million, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2010, 2009 and 2008, was $20.5 million, $11.2 million and $2.8 million, respectively.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Stock Options

Over the past few years, the Company s stock option awards have been primarily limited to senior management personnel. All stock options are granted at an exercise price equal to the market price of the Company s common stock at the date of grant. Stock options generally vest in one-third increments over a period of three years or cliff vest after three years, and expire after 10 years from the date of grant. Expense is recognized ratably over the vesting period, net of estimated forfeitures. Option grants are typically made in January of each year or upon hire for eligible plan participants.

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, 2010	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value (in millions)
Options Outstanding at December 31, 2009	3,246,030	$ 20.44	4.7	$ 85.1
Granted	257,375	47.87		
Exercised	(1,310,059)	11.88		
Forfeited	(277,045)	3.30		
Options Outstanding at December 31, 2010	1,916,301	$ 32.25	5.9	$ 61.2
Vested and Exercisable	1,239,155	$ 27.61	4.6	$ 45.1

During the years ended December 31, 2010, 2009 and 2008, 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 $53.7 million, $14.7 million and $72.8 million, respectively. The weighted-average fair values of the Company s stock options and the assumptions used in applying the Black-Scholes option pricing model were as follows:

	Year Ended December 31,		
	2010	2009	2008
Weighted-average fair value	$ 25.70	$ 26.84	$ 64.31
Risk-free interest rate	2.8%	1.5%	3.3%
Expected option life	5.0 years	5.0 years	5.0 years

Expected volatility	64%	60%	40%
Dividend yield	0.6%	0.9%	0.5%

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 and 2010, 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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of performance unit activity is as follows:

	Year Ended December 31, 2010	Weighted Average Remaining Contractual Life
Nonvested at December 31, 2009	356,444	1.5
Granted	138,399	
Forfeited		
Vested	(108,181)	
Nonvested at December 31, 2010	386,662	1.5

As of December 31, 2010, there were 108,181 performance units vested that had an aggregate intrinsic value of $10.0 million and a conversion price per share of $62.36.

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 were as follows:

	Year Ended December 31,		
	2010	2009	2008
Risk-free interest rate	1.7%	1.3%	2.9%
Expected volatility	64%	60%	40%
Dividend yield	0.6%	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. 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 0.2 million for the year ended December 31, 2010, 0.3 million for the year ended December 31, 2009 and 0.1 million for the year ended December 31, 2008.

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(15) 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, 2007	$ 3.1	$ (116.7)	$ (18.9)	$ 65.4	$ (67.1)
Net decrease in fair value of cash flow hedges				(194.5)	(194.5)
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 fair 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		(134.9)	6.5		(128.4)
December 31, 2009	3.1	(343.5)	(10.4)	167.3	(183.5)
Net increase in fair value of cash flow hedges				229.9	229.9
Reclassification from other comprehensive income to earnings		31.8	2.5	(102.4)	(68.1)
Current period change		(46.2)			(46.2)
December 31, 2010	$ 3.1	$ (357.9)	$ (7.9)	$ 294.8	$ (67.9)

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 (see Note 4 and Note 5 for information related to the Company s cash flow hedges) 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 2010 was primarily due to the strengthening of the Australian dollar against the U.S. dollar.

(16) 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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) Earnings per Share

The Company s restricted stock awards are considered participating securities. As such, the Company uses the two-class method to compute basic and diluted EPS. The following illustrates the earnings allocation method utilized in the calculation of basic and diluted EPS. Diluted EPS includes any dilutive impact of share-based compensation and the Debentures.

	Year Ended December 31,		
	2010	2009	2008
	(In millions, except per share amounts)		
EPS numerator:			
Income from continuing operations, net of income taxes	$ 805.1	$ 457.9	$ 987.9
Less: Net income attributable to noncontrolling interests	28.2	14.8	6.2
Income from continuing operations attributable to common stockholders before allocation of earnings to participating securities	776.9	443.1	981.7
Less: Earnings allocated to participating securities	(5.6)	(2.9)	(5.5)
Income from continuing operations attributable to common stockholders, after earnings allocated to participating securities[1]	771.3	440.2	976.2
Income (loss) from discontinued operations, net of income taxes	(2.9)	5.1	(28.8)
Net income attributable to common stockholders, after earnings allocated to participating securities[1]	$ 768.4	$ 445.3	$ 947.4
EPS denominator:			
Weighted average shares outstanding basic	267.0	265.5	268.9
Impact of dilutive securities	2.9	2.0	1.8
Weighted average shares outstanding diluted[2]	269.9	267.5	270.7
Basic EPS attributable to common stockholders:			
Income from continuing operations	$ 2.89	$ 1.66	$ 3.63
Income (loss) from discontinued operations	(0.01)	0.02	(0.11)
Net income	$ 2.88	$ 1.68	$ 3.52
Diluted EPS attributable to common stockholders:			
Income from continuing operations	$ 2.86	$ 1.64	$ 3.60
Income (loss) from discontinued operations	(0.01)	0.02	(0.10)
Net income	$ 2.85	$ 1.66	$ 3.50

(1) The reallocation adjustment for participating securities to arrive at the numerator used to calculate diluted EPS was less than $0.1 million for the periods presented.

(2) Weighted average shares outstanding excludes anti-dilutive shares that totaled 0.2 million for the years ended December 31, 2010 and 2009 and 0.1 million for the year ended December 31, 2008.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) Risk Management Labor Relations

As of December 31, 2010, the Company had approximately 7,200 employees, which included approximately 5,100 hourly employees. As of December 31, 2010, approximately 28% of the Company s hourly employees were represented by organized labor unions and generated 9% of its 2010 coal production. The Company could experience labor disputes, work stoppages or other disruptions in production that could negatively impact the Company s profitability.

U.S. Labor Relations. Hourly workers at the Company s Kayenta Mine in Arizona are represented by the 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, 2010.

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; the Company expects to begin negotiations prior to expiration of the existing contract. This agreement covers approximately 10% 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, 2010.

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 Construction Forestry Mining and Energy Union represents the Company s Australian subsidiaries hourly production and engineering employees, including those employed through contract mining relationships. All the Australian subsidiaries mine sites have enterprise bargaining agreements. In 2010, the Company successfully renegotiated new labor agreements at its North Goonyella, Wilkie Creek and Metropolitan mines. The North Goonyella Mine agreement will expire in 2012 and the Wilkie Creek and Metropolitan Mine agreements will expire in 2013. The labor agreement for the Wambo coal handling plant expires in April 2011; negotiations for a new agreement are expected to commence in March 2011. The labor agreement for the North Wambo Underground Mine was renewed in early 2009 and will expire in April 2012.

(19) Financial Instruments and Guarantees 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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Instruments with Off-Balance Sheet Risk

The Company has letters of credit, bank guarantees, surety bonds and corporate guarantees (such as self bonds) in support of the Company s reclamation, coal lease and workers compensation obligations as follows as of December 31, 2010:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other[(1)]	Total
			(Dollars in millions)		
Self bonding	$ 920.3	$	$	$	$ 920.3
Surety bonds	577.2	110.3	7.3	10.5	705.3
Bank guarantees	127.2			128.3	255.5
Letters of credit	0.1		68.8	87.4	156.3
	$ 1,624.8	$ 110.3	$ 76.1	$ 226.2	$ 2,037.4

(1) Other includes letter of credit obligations described below and an additional $138.9 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, 2010, the Company s maximum reimbursement obligation to the commercial bank was in turn supported by four letters of credit totaling $42.7 million. During 2010, the Company entered into a bilateral cash collateralized agreement for these letters of credit whereby the Company posted cash collateral in lieu of utilizing the Company s Credit Facility. Such cash collateral is classified within cash and cash equivalents given the Company has the ability to substitute letters of credit at any time for this cash collateral and it is therefore readily available to the Company.

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 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, 2010. 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, 2010, the Company had a $7.6 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.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts Receivable Securitization

The Company has an accounts receivable securitization program (securitization program) through its wholly-owned, bankruptcy-remote subsidiary (Seller). Under the securitization program, beginning in 2010, the Company contributes, on a revolving basis, trade receivables of most of the Company s U.S. subsidiaries to the Seller, which then sells the receivables in their entirety to a consortium of unaffiliated asset-backed commercial paper conduits (the Conduits). After the sale, the Company, as servicer of the assets, collects the receivables on behalf of the Conduits for a nominal servicing fee. The Company utilizes proceeds from the sale of its accounts receivable as an alternative to short-term borrowings under the Company s Credit Facility, effectively managing its overall borrowing costs and providing an additional source for working capital. The securitization program was renewed in May 2009 and amended in December 2009 in order to qualify for sale accounting under a newly adopted accounting standard related to financial asset transfers. Prior to amending the securitization program, the Company sold senior undivided interests in certain of its accounts receivable and retained subordinated interests in those receivables. The current securitization program 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 Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Of the receivables sold to the Conduits, a portion of the amount due to the Seller is deferred until the ultimate collection of the underlying receivables. During the year ended December 31, 2010, the Company received total consideration of $4,576.3 million related to accounts receivable sold under the securitization program, including $2,460.1 million of cash up front from the sale of the receivables, an additional $1,953.6 million of cash upon the collection of the underlying receivables, and $162.6 million that had not been collected at December 31, 2010 and was recorded at fair value which approximates carrying value. The reduction in accounts receivable as a result of securitization activity with the Conduits was $150.0 million at December 31, 2010 and $254.6 million at December 31, 2009.

The securitization activity has been reflected in the consolidated statements of cash flows as operating activity because both the cash received from the Conduits upon sale of receivables as well as the cash received from the Conduits upon the ultimate collection of receivables are not subject to significantly different risks given the short-term nature of the Company s trade receivables. The Company recorded expense associated with securitization transactions of $2.4 million, $4.0 million and $10.8 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Other

The Company had a liability recorded of $50.2 million as of December 31, 2010 and $52.3 million as of December 31, 2009 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, and the Company assumes that no amounts could be recovered from third parties.

In connection with the development of the Prairie State Energy Campus (Prairie State), a 1,600 megawatt coal-fuel electricity generation project currently under construction, each owner, including one of the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s subsidiaries, has issued a guarantee for its proportionate share (5.06% for the Company) of the construction costs under the Target Price Engineering, Procurement and Construction Agreement with Bechtel Power Corporation.

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.

(20) Commitments and Contingencies

Commitments

As of December 31, 2010, purchase commitments for capital expenditures were $458.2 million, all of which is obligated within the next three years with $406.7 million obligated in the next year. The purchase commitments for capital expenditures represent an increase of $386.5 million over amounts committed as of December 31, 2009 and primarily relate to new mines and expansion and extension projects in Australia and the U.S. Commitments made for expenditures under coal leases as reflected in Note 9. The Company also has various long- and short-term take or pay arrangements associated with rail and port commitments in Australia for the delivery of coal including amounts relating to export facilities. As of December 31, 2010, these commitments totaled $2,892.9 million with $1,109.1 million obligated within the next five years, of which $217.5 million was obligated within the next year. During 2010, the Company recognized approximately $145 million of expense, reflected in Operating costs and expenses in the consolidated statements of operations, related to these take or pay arrangements.

The Company controls a 17.7% interest in NCIG, a coal transloading facility in Newcastle, Australia that is backed by take or pay agreements. The total loading capacity for stage one is 33 million tons per year, of which the Company s share is 5.8 millions tons. In the second quarter of 2010, stage one of construction was substantially completed and operations commenced. NCIG is currently operating at a reduced rate as part of its ramp-up to full capability, which is anticipated to occur by late 2011. Phase one of stage two construction has been approved and is under way. When complete, it is expected to provide the Company with approximately 2 million tons of additional annual throughput capacity beginning in mid-year 2012. Financing for phase one of stage two of construction closed in the third quarter of 2010 with the Company providing its pro-rata share of funding of $59.7 million Australian dollars ($54.8 million U.S. dollars) where the Company received underlying debt and equity securities of NCIG for its contributions. Subsequent to the funding, the Company sold a portion of the debt securities for $10.6 million.

A subsidiary of the Company owns a 5.06% undivided interest in Prairie State. The Company invested $76.0 million, $56.8 million and $40.9 million during the years ended December 31, 2010, 2009 and 2008, respectively, representing its 5.06% share of the construction costs for those periods. Included in Investments and other assets in the consolidated balance sheets as of December 31, 2010 and December 31, 2009, are costs of $202.5 million and $126.5 million, respectively. The Company s share of total construction costs for Prairie State is expected to be approximately $250 million with most of the remaining funding expected in 2011.

The Company is an equity partner in GreenGen, a partnership to fund the construction in China of a near-zero emissions coal-fueled power plant with carbon capture and storage. During the year ended December 31, 2010, the Company spent $3.1 million representing its 6.0% share of the construction costs, which is reflected as capitalized development costs as part of Investments and other assets in the consolidated balance sheets. There were no expenditures for GreenGen for 2009 or 2008. The Company s share of total construction costs for GreenGen is expected to be approximately $60 million.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Contingencies

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 alleged 16 claims, including Civil Racketeer Influenced and Corrupt Organizations Act (RICO) violations and fraud. On April 12, 2010, the Navajo Nation filed an amended complaint to substantially narrow the scope of its claims by removing the RICO allegations but leaving the other 12 common law tort and contractual claims. 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, punitive damages of at least $1 billion, a determination that Peabody Western s two coal leases terminated due to Peabody Western s breach of these leases and a reformation of these leases to adjust the royalty rate to 20%. The court allowed the Hopi Tribe to intervene in this lawsuit, and the Hopi Tribe sought 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. The U.S. Supreme Court has 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.

In October 2010, the Company and the other defendants settled the Hopi claims, and the court dismissed those claims. The court ordered the Navajo Nation and the defendants to mediate the case, and mediation commenced in November 2010.

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 five million tons under the agreement, which expired on December 31, 2007. 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 June 30, 2009, the court granted Gulf Power s motion for partial summary judgment and denied the Company subsidiary s motion for summary judgment. The damages portion of the trial was held in February 2010. On September 30, 2010, the court entered its order on damages, awarding Gulf Power zero dollars in damages and the Company its costs to defend the lawsuit. The Company is also seeking its reasonable attorney s fees incurred since October 15, 2008. On November 1, 2010, Gulf Power filed a motion to alter or amend the judgment, contesting the trial court s damages order, to which the Company objected. The court has not yet ruled on the motion.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 pending in the U.S. District Court for the Northern District of Oklahoma 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 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 separate lawsuit in the U.S. District Court for the Northern District of Oklahoma against Gold Fields, five other companies and the U.S. The plaintiffs sought 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 filed a third-party complaint against the U.S. and other parties. In October 2010, the parties entered into a settlement agreement and the case was dismissed.

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.

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 13 additional sites, bringing the total to 18, 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 $51.1 million as of December 31, 2010 and $49.5 million as of December 31, 2009, $6.3 million and $7.9 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 June 2005, Gold Fields and other PRPs received a letter from the U.S. Department of

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 June 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 total 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 putative 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, a three-judge panel of the U.S. Court of Appeals for the Fifth Circuit (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 court held that plaintiffs did not satisfy the prudential standing requirement for their unjust enrichment, fraudulent misrepresentation and civil conspiracy claims and dismissed those claims and ordered that the case be remanded to the district court for further proceedings. In March 2010, the Fifth Circuit vacated the panel opinion and ordered a hearing en banc before the full Fifth Circuit to consider plaintiffs appeal. After the en banc court was properly constituted, a recusal by one of the judges resulted in the en banc court losing its quorum. On May 28, 2010, the Fifth Circuit issued an order indicating that the court had no authority to reinstate the panel decision and directing the clerk to dismiss the appeal. Plaintiffs filed a Petition for Mandamus with the U.S. Supreme Court. On January 10, 2011, the U.S. Supreme Court denied the plaintiffs Petition for Mandamus. As a result, the trial court s dismissal of the case is final.

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 June 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 to the U.S. Court of Appeals for the Ninth Circuit. The parties have filed their respective briefs with the court.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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 June 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, 2010 and 2009 is presented below.

	Year Ended December 31, 2010 (In millions except per share data)			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Revenues	$ 1,515.6	$ 1,661.4	$ 1,864.7	$ 1,818.3
Operating profit	242.2	324.4	444.7	314.4
Income from continuing operations, net of income taxes	137.1	214.7	237.6	215.7
Net income	136.7	214.2	236.3	215.0
Net income attributable to common stockholders	133.7	206.2	224.1	210.0
Basic earnings per share continuing operations[1]	0.50	0.77	0.84	0.78
Diluted earnings per share continuing operations[1]	$ 0.50	$ 0.76	$ 0.83	$ 0.77
Weighted average shares used in calculating basic earnings per share	266.5	266.6	267.1	267.7
Weighted average shares used in calculating diluted earnings per share	268.2	268.3	268.6	270.3

(1)

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

Operating profit in the second, third and fourth quarters reflects higher contract pricing in Australia. Operating profit for the fourth quarter includes an adverse impact related to flooding in Queensland, Australia and lower results from the Company s Trading and Brokerage operations. Income from continuing operations, net of income taxes in the first, third and fourth quarters included non-cash tax expense of $5.4 million, $42.7 million, and $18.8 million, respectively, from the remeasurement of non-U.S. income tax accounts, while the second quarter included a non-cash benefit of $19.3 million.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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 sum to the amounts for the year as each period is computed on a discrete basis.

Operating profit in the second, third and fourth quarters reflects 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 non-cash 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.

(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. 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. The business of the Company s 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. For the year ended December 31, 2010, 84% of the Company s total sales (by volume) were to U.S. electricity generators, 14% were to customers outside the U.S. and 2% were to the U.S. industrial sector. 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

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 metallurgical and thermal coal. The Company s Trading and Brokerage segment brokers coal sales of other coal producers both as principal and agent, and trades 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, 2010 were as follows (total assets as of December 31, 2010):

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
			(Dollars in millions)			
Revenues	$ 2,706.3	$ 1,320.6	$ 2,520.0	$ 291.1	$ 22.0	$ 6,860.0
Adjusted EBITDA	816.7	322.1	953.8	77.2	(354.7)	1,815.1
Total assets	3,008.4	608.0	3,603.4	398.2	3,745.1	11,363.1
Additions to property, plant, equipment and mine development	143.3	224.9	147.8	0.9	40.1	557.0
Federal coal lease expenditures						
Loss from equity affiliates					1.7	1.7
Additions to advance mining royalties	1.3	1.3			3.1	5.7

Operating segment results for the year ended December 31, 2009 were as follows (total assets as of December 31, 2009):

	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	3,087.6	444.4	3,386.8	673.0	2,363.5	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

Table of Contents

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating segment results for the year ended December 31, 2008 were as follows (total assets as of December 31, 2008):

	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

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

	Year Ended December 31, 2010	2009	2008
		(Dollars in millions)	
Total adjusted EBITDA	$ 1,815.1	$ 1,290.1	$ 1,846.9
Depreciation, depletion and amortization	(440.9)	(405.2)	(402.4)
Asset retirement obligation expense	(48.5)	(40.1)	(48.2)
Interest expense	(222.1)	(201.2)	(227.0)
Interest income	9.6	8.1	10.0
Income tax provision	(308.1)	(193.8)	(191.4)
Income from continuing operations, net of income taxes	$ 805.1	$ 457.9	$ 987.9

(23) Supplemental Guarantor/Non-Guarantor Financial Information

In accordance with the indentures governing the 6.875% Senior Notes due March 2013 (extinguished in 2010), the 5.875% Senior Notes due March 2016, the 7.375% Senior Notes due November 2016, the 6.5% Senior Notes due September 2020 and the 7.875% Senior Notes due November 2026 (collectively the Senior Notes), 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 holders of the Senior Notes. The following historical financial statement information is provided for the Guarantor/Non-Guarantor Subsidiaries.

Table of Contents

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Year Ended December 31, 2010				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$	$ 3,716.2	$ 3,916.9	$ (773.1)	$ 6,860.0
Costs and expenses					
Operating costs and expenses	(145.1)	2,616.4	3,142.8	(773.1)	4,841.0
Depreciation, depletion and amortization		297.9	143.0		440.9
Asset retirement obligation expense		33.2	15.3		48.5
Selling and administrative expenses	31.6	194.3	6.3		232.2
Other operating (income) loss:					
Net (gain) loss on disposal or exchange of assets		(34.5)	4.5		(30.0)
(Income) loss from equity affiliates	(838.4)	7.1	6.0	827.0	1.7
Interest expense	219.7	52.8	17.9	(68.3)	222.1
Interest income	(18.8)	(21.8)	(37.3)	68.3	(9.6)
Income from continuing operations before income taxes	751.0	570.8	618.4	(827.0)	1,113.2
Income tax provision (benefit)	(24.2)	176.0	156.3		308.1
Income from continuing operations, net of income taxes	775.2	394.8	462.1	(827.0)	805.1
Loss from discontinued operations, net of income taxes	(1.2)	(1.7)			(2.9)
Net income	774.0	393.1	462.1	(827.0)	802.2
Less: Net income attributable to noncontrolling interests			28.2		28.2
Net income attributable to common stockholders	$ 774.0	$ 393.1	$ 433.9	$ (827.0)	$ 774.0

Table of Contents

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Year Ended December 31, 2009				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$	$ 4,449.3	$ 2,312.5	$ (749.4)	$ 6,012.4
Costs and expenses					
Operating costs and expenses	104.4	3,383.8	1,733.8	(749.4)	4,472.6
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	5.6		203.8
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

Table of Contents

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING 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	1,815.3	(208.8)	4,589.7
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	3.7		197.3
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

F-63

Table of Contents

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING BALANCE SHEETS

	December 31, 2010				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Reclassifications/ Eliminations	Consolidated
	(Dollars in millions)				
Assets					
Current assets					
Cash and cash equivalents	$ 903.8	$ 5.2	$ 386.2	$	$ 1,295.2
Accounts receivable, net	2.1	5.5	550.6		558.2
Inventories		168.0	164.9		332.9
Assets from coal trading activities, net		23.8	168.7		192.5
Deferred income taxes		78.6	47.9	(6.1)	120.4
Other current assets	307.9	30.7	120.4		459.0
Total current assets	1,213.8	311.8	1,438.7	(6.1)	2,958.2
Property, plant, equipment and mine development					
Land and coal interests		4,860.7	2,796.3		7,657.0
Buildings and improvements		945.8	134.0		1,079.8
Machinery and equipment		1,300.6	398.7		1,699.3
Less: accumulated depreciation, depletion and amortization		(2,374.4)	(635.6)		(3,010.0)
Property, plant, equipment and mine development, net		4,732.7	2,693.4		7,426.1
Investments and other assets	9,331.0	179.8	99.1	(8,631.1)	978.8
Total assets	$ 10,544.8	$ 5,224.3	$ 4,231.2	$ (8,637.2)	$ 11,363.1
Liabilities and Stockholders Equity					
Current liabilities					
Current maturities of long-term debt	$ 25.0	$	$ 18.2	$	$ 43.2
Payables to (receivables from) affiliates, net	2,225.3	(2,528.3)	303.0		
Liabilities from coal trading activities, net		29.5	152.2		181.7
Deferred income taxes	6.1			(6.1)	
Accounts payable and accrued expenses	47.4	777.2	464.2		1,288.8
Total current liabilities	2,303.8	(1,721.6)	937.6	(6.1)	1,513.7
	2,609.6	0.1	97.1		2,706.8

Long-term debt, less current maturities					
Deferred income taxes	93.2	135.4	311.2		539.8
Notes payable to (receivables from) affiliates, net	818.9	(825.3)	6.4		
Other noncurrent liabilities	58.6	1,652.8	202.1		1,913.5
Total liabilities	5,884.1	(758.6)	1,554.4	(6.1)	6,673.8
Peabody Energy Corporation s stockholders equity	4,660.7	5,982.9	2,648.2	(8,631.1)	4,660.7
Noncontrolling interests			28.6		28.6
Total stockholders equity	4,660.7	5,982.9	2,676.8	(8,631.1)	4,689.3
Total liabilities and stockholders equity	$ 10,544.8	$ 5,224.3	$ 4,231.2	$ (8,637.2)	$ 11,363.1

Table of Contents

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING 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

F-65

Table of Contents

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2010			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
	(Dollars in millions)			
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$ (126.4)	$ 1,090.6	$ 139.5	$ 1,103.7
Net cash provided by (used in) discontinued operations	(14.2)	(2.4)		(16.6)
Net cash provided by (used in) operating activities	(140.6)	1,088.2	139.5	1,087.1
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development		(404.5)	(152.5)	(557.0)
Investment in Prairie State Energy Campus		(76.0)		(76.0)
Proceeds from disposal of assets, net of notes receivable		14.1	5.1	19.2
Investment in equity affiliates and joint ventures		(15.0)	(3.8)	(18.8)
Investments in debt and equity securities			(74.6)	(74.6)
Proceeds from sale of debt securities			12.4	12.4
Other, net		(8.7)	(0.1)	(8.8)
Net cash used in investing activities		(490.1)	(213.5)	(703.6)
Cash Flows From Financing Activities				
Proceeds from long-term debt	1,150.0			1,150.0
Payments of long-term debt	(1,146.8)		(20.5)	(1,167.3)
Dividends paid	(79.4)			(79.4)
Repurchase of employee common stock relinquished for tax withholding	(13.5)			(13.5)
Payment of debt issuance costs	(32.2)			(32.2)
Excess tax benefits related to share-based compensation	51.0			51.0
Proceeds from stock options exercised	16.4			16.4
Other, net	5.9	(5.9)	(2.1)	(2.1)
Transactions with affiliates, net	724.6	(587.2)	(137.4)	
Net cash provided by (used in) financing activities	676.0	(593.1)	(160.0)	(77.1)

Net change in cash and cash equivalents	535.4	5.0	(234.0)	306.4
Cash and cash equivalents at beginning of year	368.4	0.2	620.2	988.8
Cash and cash equivalents at end of year	$ 903.8	$ 5.2	$ 386.2	$ 1,295.2

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING 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	$ (213.7)	$ 792.7	$ 476.8	$ 1,055.8
Net cash provided by (used in) discontinued operations	7.4	(5.3)	(7.7)	(5.6)
Net cash provided by (used in) operating activities	(206.3)	787.4	469.1	1,050.2
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
Investment in equity affiliates and joint ventures		(5.0)	(10.0)	(15.0)
Other, net		(5.8)	(0.3)	(6.1)
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
Repurchase of employee common stock relinquished for tax withholding	(2.3)			(2.3)
Other, net	5.1		(7.1)	(2.0)
Transactions with affiliates, net	473.9	(454.6)	(19.3)	
Net cash provided by (used in) financing activities	413.5	(454.6)	(63.5)	(104.6)
Net change in cash and cash equivalents	207.2	(4.3)	336.2	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	$ 368.4	$ 0.2	$ 620.2	$ 988.8

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING 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	$ 28.7	$ 465.6	$ 926.5	$ 1,420.8
Net cash used in discontinued operations	(94.5)	(17.3)	(11.2)	(123.0)
Net cash provided by (used in) operating activities	(65.8)	448.3	915.3	1,297.8
Net cash provided by continuing operations				
Net cash provided by (used in) discontinued operations				
Net cash provided by operating activities		(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
Investments in equity affiliates and joint ventures		(2.6)		(2.6)
Other, net		(5.7)	(0.3)	(6.0)
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)
Repurchase of employee common stock relinquished for tax withholding	(11.0)			(11.0)
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	220.0	(93.9)	(624.1)	(498.0)

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

Table of Contents

Schedule II

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, 2010					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$ 17.2	$ 1.9	$ (0.2)	$ 1.0[2]	$ 19.9
Reserve for materials and supplies	6.2	0.9	(0.9)		6.2
Allowance for doubtful accounts	18.3	26.7	(6.9)	(7.8)[3]	30.3
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

(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.

Table of Contents

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
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	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 .7	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).
4 .8	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 .9	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 .10	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 .11	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).

Table of Contents

Exhibit No.	Description of Exhibit
4 .12	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 .13	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 .14	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 .15	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 .16	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 .17	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 .18	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 .19	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 .20	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).
4 .21	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 .22	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 .23	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 .24	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).

Table of Contents

Exhibit No.	Description of Exhibit
4 .25	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 .26	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 .27	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 .28	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 .29	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 .30	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 .31	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 .32	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 .33	Thirty-Third Supplemental Indenture, dated as of August 25, 2010, among Peabody Energy Corporation, the guarantors named therein and U.S. Bank National Association, as trustee, relating to the 6.500% Senior Notes due 2020 (Incorporated by reference to Exhibit 4.1 of the Registrant s Current Report on Form 8-K filed on August 27, 2010).
4 .34	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 .35	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).
4 .36	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 .37	

	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 .38	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).
4 .39	Notice of Adjustment of Conversion Rate of 4.75% Convertible Junior Subordinated Debentures due 2066, dated February 8, 2010 (Incorporated by reference to Exhibit 4.1 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).

Table of Contents

Exhibit No.	Description of Exhibit
10 .1	Credit Agreement, dated as of June 18, 2010, by and among the Company, Bank of America, N.A., as administrative agent, swing line lender and L/C issuer, and Banc of America Securities LLC, Citigroup Global Markets, Inc. and HSBC Securities (USA) Inc., as joint lead arrangers and joint book managers, and the lenders named therein (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on June 24, 2010).
10 .2	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 .3	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 .4	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 .5	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 .6	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 .7	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 .8	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 .9	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 .10	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 .11	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 .12	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 .13	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).
10 .14	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 .15	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 .16	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 .17	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).

Table of Contents

Exhibit No.	Description of Exhibit
10 .18*	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 .19*	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 .20*	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 .21*	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 .22*	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 .23*	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 .24*	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 .25*	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 .26*	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 .27*	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 .28*	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 .29*	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 .30*	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).
10 .31*	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 .32*	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 .33*	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 .34*	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 .35*	

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).

Exhibit No.	Description of Exhibit
10 .36*	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 .37*	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 .38*	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 .39*	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 .40*	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 .41*	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 .42*	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 .43*	Form of Deferred Stock Units Agreement for Non-Employee Directors.
10 .44*	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 (Incorporated by reference to Exhibit 10.45 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .45*	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 (Incorporated by reference to Exhibit 10.46 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .46*	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 (Incorporated by reference to Exhibit 10.47 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .47*	2009 Amendment entered into effective December 31, 2009 to the Performance Units Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.48 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .48*	2009 Amendment entered into effective December 31, 2009 to the Performance Units Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.49 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .49*	2010 Amendment entered into effective March 17, 2010, to the 2008 Performance Units Award Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.3 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10 .50*	2010 Amendment entered into effective March 17, 2010, to the 2009 Performance Units Award Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.4 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended

	March 31, 2010).
10 .51*	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).

Table of Contents

Exhibit No.	Description of Exhibit
10 .52*	Amendment to the Amended and Restated Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.51 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .53*	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).
10 .54*	Amendment to the Amended and Restated Australian Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.53 of the Registrant s Annual Report on Form 10-K for the year ended December 31, 2009).
10 .55*	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 .56*	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 .57*	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 .58*	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 .59*	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 .60*	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 .61*	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 .62*	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 .63*	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 .64*	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 .65*	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 .66*	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 .67*	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 .68*	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 .69*	

	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 .70*	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).

Table of Contents

Exhibit No.	Description of Exhibit
10 .71*	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 .72*	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).
10 .73*	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 .74*	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 .75*	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 .76*	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 .77*	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 .78*	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 .79*	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 .80*	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 .81*	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 .82*	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 .83*	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 .84*	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 .85*	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 .86	

Third Amended and Restated Receivables Purchase Agreement, dated as of January 25, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, 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 January 27, 2010).

Table of Contents

Exhibit No.	Description of Exhibit
10 .87	First Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of March 1, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, 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 10.2 of the Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10 .88	Second Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of May 11, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, 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 May 17, 2010).
10 .89	Third Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of September 16, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, 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 Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
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.
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, 2010 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.