PEABODY ENERGY CORP
Form 10-K
February 27, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(X)	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the Fiscal Year Ended December 31, 2011
or	
( )	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 1-16463

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

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

(314) 342-3400
Registrant's telephone number, including area code
Securities Registered Pursuant to Section 12(b) of the Act:

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

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

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

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 ( ) No (X)

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 (X) No ( )

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 (X) No ( )

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. ( )

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 (X)	Accelerated filer ( )	Non-accelerated filer ( )	Smaller reporting company ( )

(Do not check if a smaller reporting company)
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ( ) No (X)
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, 2011: Common Stock, par value $0.01 per share, $15.9 billion.
Number of shares outstanding of each of the Registrant’s classes of Common Stock, as of February 17, 2012: Common Stock, par value $0.01 per share, 272,259,729 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 2012 Annual Meeting of Shareholders (the Company’s 2012 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

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CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

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

- global demand for coal, including the seaborne thermal and metallurgical coal markets;
- price volatility, particularly in higher-margin products and in our trading and brokerage businesses;
- impact of alternative energy sources, including natural gas and renewables;
- impact of weather and natural disasters 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, contract miners, 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;
- integration of the newly acquired Macarthur Coal Limited (Macarthur) operations;
- successful implementation of business strategies;
- 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 and mine safety requirements, changes in income tax regulations or other regulatory taxes;
- litigation, including claims not yet asserted;
- terrorist attacks or threats;
- impacts of pandemic illnesses; and
- other factors, including those discussed in Legal Proceedings, set forth in Item 3 of this report and Risk Factors, set forth in Item 1A of this report.

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

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

PART I

Item 1. Business.

History and Development of Business

Peabody Energy Corporation is the world’s largest private-sector coal company. We own interests in 30 coal mining operations, including a majority interest in 29 coal operations located in the United States (U.S.) and Australia and a 50% equity interest in the Middlemount Mine in Australia. We also own an equity interest in a joint venture mining operation in Venezuela. In addition to our mining operations, we market, broker and trade coal through our Trading and Brokerage segment.

We were incorporated in Delaware in 1998 and became a public company in 2001. Our history in the coal mining business dates back to 1883. Over the past decade, we have made strategic acquisitions and divestitures to position our company to serve the highest demand coal markets. Acquisitions and divestitures of note include the following.

- In 2006, we expanded our presence in Australia with the acquisition of Excel Coal Limited.
- In 2007, we spun off Patriot Coal Corporation (Patriot) through a dividend of all outstanding shares, which included mines in West Virginia and Kentucky.
- In 2011, we acquired Macarthur, an independent coal company in Australia, which included two operating mines, a 50% equity-affiliate joint venture arrangement and several development projects, along with coal reserves of approximately 213 million tons (approximately 142 million tons on an attributable basis).

In 2011, we continued advancing multiple organic growth projects in Australia and the U.S. that involved future mines, as well as the expansion and extension of existing mines. In 2012 and the near term, our plans for our mining operations include further investments in organic growth projects. In the U.S., development work is expected to begin on our new Gateway North Mine in Illinois and the new Twentymile Sage Creek portal that will serve as an extension of our Twentymile Mine in Colorado. In Australia, we will continue advancing multiple projects that are expected to increase our seaborne coal volumes over the next few years. We also plan to convert our Wilpinjong and Millennium mines in Australia from contract mining to owner-operated mines. In addition, the integration of Macarthur into our Australian operations will continue as we seek to realize synergies through blending, sales and marketing, administrative costs, purchasing, infrastructure and capital project development. We also plan to accelerate development of the new Codrilla Mine, a legacy Macarthur project, which is expected to produce first coal in late 2013.

Other future plans include the continued expansion of our global trading and brokerage platform, which will include the additional sourcing of coal of third-parties from offtake arrangements and joint venture arrangements. We will also continue to explore opportunities to expand our presence in the Asia-Pacific region, such as through partnerships with other companies to utilize our mining experience for joint mine development.

Our core strategies to achieve growth are:

1) Executing the basics of best-in-class safety, operations and marketing;
2) Capitalizing on organic growth opportunities; and
3) Expanding in high-growth global markets.

We are also participating in new generation and Btu Conversion technologies designed to expand the uses of coal technologies, including carbon capture and storage.

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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 coal reserve and real estate holdings.

Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado mines. The mines in that segment are characterized by predominantly surface mining extraction processes and coal with a lower sulfur content and Btu. In addition, the customer transportation costs are generally higher due to longer shipping distances.

Our Midwestern U.S. Mining operations include our mines in Illinois and Indiana, which are characterized by a mix of surface and underground mining extraction processes and coal with a higher sulfur content and Btu. In addition, the customer transportation costs are generally lower due to shorter shipping distances. The principal business of our U.S. mining operations is the sale of thermal (steam) coal, sold primarily to electric utilities in the U.S. with a portion sold into the seaborne markets.

Our Australian Mining operations consist of our mines in Queensland and New South Wales, Australia. The mines in that segment are characterized by both surface and underground extraction processes, mining various qualities of metallurgical (low-sulfur, high Btu coal) and thermal coal. The metallurgical coal qualities include hard coking coal, semi-hard coking coal, semi-soft coal and pulverized coal injection (PCI) coal. PCI coal is generally used by steel producers as a replacement for coke made from coking coal. Our recent acquisition of Macarthur increased our proven and probable reserves, which included low volatile PCI (LV PCI) coal, coking coal and thermal coal. Our Australian Mining operations are primarily export focused with customers spread across several countries, while a portion of our coal is sold to Australian steel producers and power generators. Generally, revenues from individual countries vary year by year based on the demand for electricity, the demand for steel, the strength of the global economy and several other factors including those specific to each country.

Financial information regarding our operating segments is contained in Note 25 to our consolidated financial statements.

Mining Segments

The maps that follow display our mine locations as of December 31, 2011, excluding mines held for sale. 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

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Australian Mining Operations

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The table below presents information regarding each of our 30 mines (excluding mines held for sale), including mine location, type of mine, mining method, coal type, transportation method and tons sold in 2011. The mines are sorted by tons sold within each mining segment.

Mine	Location	Mine Type	Mining Method	Coal Type	Transport Method	2011Tons Sold (In millions)
Western U.S. Mining						
North Antelope Rochelle	Wright, WY	S	DL, T/S	T	R	109.0
Caballo	Gillette, WY	S	D, T/S	T	R	24.2
Rawhide	Gillette, WY	S	D, T/S	T	R	15.0
El Segundo	Grants, NM	S	T/S	T	R	8.0
Kayenta	Kayenta, AZ	S	DL, T/S	T	R	7.9
Twentymile	Oak Creek, CO	U	LW	T	R, T	7.5
Lee Ranch	Grants, NM	S	DL, T/S	T	R	2.0
Midwestern U.S. Mining						
Bear Run	Carlisle, IN	S	DL, D, T/S	T	T, R	6.5
Gateway	Coulterville, IL	U	CM	T	T, R, R/B	3.5
Francisco Underground	Francisco, IN	U	CM	T	R	3.0
Somerville Central	Oakland City, IN	S	DL, D, T/S	T	R, T/R, T/B	2.8
Willow Lake	Equality, IL	U	CM	T	T/B	2.2
Cottage Grove	Equality, IL	S	D, T/S	T	T/B	1.9
Wild Boar	Lynnville, IN	S	D, T/S	T	T, R, R/B	1.8
Somerville North (1)	Oakland City, IN	S	D, T/S	T	R, T/R, T/B	1.4
Viking — Corning Pit	Cannelburg, IN	S	D, T/S	T	T, T/R	1.4
Somerville South (1)	Oakland City, IN	S	D, T/S	T	R, T/R, T/B	1.2
Air Quality	Vincennes, IN	U	CM	T	T, T/R, T/B	1.2
Wildcat Hills Underground	Eldorado, IL	U	CM	T	T/B	1.0
Other (2)	—	—	—	—	—	2.4
Australian Mining						
Wilpinjong *	Wilpinjong, New South Wales	S	T/S	T	R, EV	9.8
North Wambo Underground (1)	Warkworth, New South Wales	U	LW	T/P	R, EV	3.1
Wambo Open-Cut * (1)	Warkworth, New South Wales	S	T/S	T	R, EV	2.9
Burton *	Glenden, Queensland	S	T/S	T/M	R, EV	2.3
Millennium *	Moranbah, Queensland	S	T/S	M	R, EV	1.9
Metropolitan	Helensburgh, New South Wales	U	LW	M	R, EV	1.6
Eaglefield *	Glenden, Queensland	S	T/S	M	R, EV	1.6
North Goonyella	Glenden, Queensland	U	LW	M	R, EV	1.2
Coppabella (3)	Moranbah, Queensland	S	DL, T/S	P	R, EV	0.5
Moorvale * (3)	Moranbah, Queensland	S	T/S	T/M/P	R, EV	0.4
Middlemount (4)	Middlemount, Queensland	S	T/S	M/P	R, EV	-

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	T	Thermal/Steam
*	Mine is operated by a contract miner	M	Metallurgical
		P	Pulverized Coal Injection

(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.

(3) We own a 73.3% undivided interest in an unincorporated joint venture that owns the Coppabella and Moorvale mines. Tons sold is for the period from the date of the acquisition (October 26, 2011) to December 31, 2011.

(4) We own a 50.0% equity interest in Middlemount Coal Pty Ltd., which owns the Middlemount Mine in Queensland, Australia that was acquired as part of the Macarthur acquisition.

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We also 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.

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

Trading and Brokerage Segment

We have a global coal trading and brokerage platform with trading and business offices in China, Australia, the United Kingdom, Singapore, Indonesia, Germany and the U.S. Through our Trading and Brokerage segment, we engage in the brokering of coal sales both as principal and agent in support of various coal production-related activities that may involve coal to be produced from our mines, coal sourcing arrangements with third-party mining companies or offtake agreements with producers. We also engage in 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.

Corporate and Other Segment

Our Corporate and Other Segment includes selling and administrative items, activity associated with our joint ventures, resource management activity, past mining obligations and our other commercial activities such as generation development and Btu Conversion development costs.

Resource Management. We hold approximately 9.0 billion tons of proven and probable coal reserves and more than 500,000 acres of surface property. We have an ongoing asset optimization program where 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 have an interest in a coal export terminal in Newport News, Virginia that exports both metallurgical and thermal coal primarily to European and Brazilian markets.

Generation Development. We are a 5.06% owner in the Prairie State Energy Campus (Prairie State), a 1,600 megawatt coal-fueled electricity generation project. We are responsible for our 5.06% share of costs and marketing and selling of our share of electricity generated by the facility. The first unit began operations in 2011 and the second unit is expected to commence operations in 2012.

Btu Conversion. Btu Conversion involves projects designed to expand the uses of coal through coal-to-liquids (CTL) and coal gasification technologies. We own an equity interest in GreatPoint Energy, Inc., which is commercializing its coal-to-pipeline quality natural gas technology. We also 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 and is expected to begin operations during 2012. In Australia, we have an ongoing 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.

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Mongolia Joint Venture. We own a 50% interest in Peabody-Winsway Resources B.V., a joint venture agreement with Winsway Coking Coal Holding Ltd. (Winsway), a Hong Kong stock exchange listed company. The joint venture is in the development stage and plans to ship metallurgical and thermal coal to Asian markets once developed. In 2011, we acquired a 5.1% equity interest in Winsway further strengthening the strategic partnership between the two companies.

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 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.

Middlemount Mine. Through the acquisition of Macarthur, we own a 50% interest in the Middlemount Mine. The mine development was completed in late 2011 and test coal shipments to customers are ongoing. The mine is expected to reach full production in 2012.

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%, 91% and 93% of our worldwide sales (by volume) for the years ended December 31, 2011, 2010 and 2009, respectively.

For the year ended December 31, 2011, we derived 23% of our total coal sales revenues from our five largest customers. Those five customers were supplied primarily from 24 coal supply agreements (excluding trading transactions) expiring at various times from 2012 to 2025. The contract contributing the greatest amount of annual revenue in 2011 was approximately $311 million, or approximately 4% of our 2011 total revenue base and is due to expire in 2019.

Our sales backlog includes coal supply agreements subject to price reopener and/or extension provisions. As of January 31, 2012 and 2011, 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 2011 production of 227.5 million tons. As of January 31, 2012, 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. Revenue from our Australian Mining segment represented approximately 39%, 36% and 26% of our total revenue base for the years ended December 31, 2011, 2010 and 2009, respectively. Our Australian coal mining activities accounted for 11%, 12% and 9% of our mining operations sales volume in 2011, 2010 and 2009, respectively. 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.

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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 U.S. and Australian 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 5 for transportation methods by mine.

Our primary ports used for U.S. exports are the Dominion Terminal Associates coal terminal in Newport News, Virginia, the United Bulk Terminal near New Orleans, Louisiana and the Kinder Morgan terminal near Houston, Texas. Our U.S. mining operations exported approximately 3%, 1% and 1% of its tons sold for the years ended December 31, 2011, 2010 and 2009, respectively.

In Australia, we own interests in three east coast coal export terminals that are primarily funded through take-or-pay arrangements (see "Liquidity and Capital Resources" for additional information). In Queensland, seaborne metallurgical and thermal coal from our mines, including the Coppabella and Moorvale mines added with the acquisition of Macarthur, is exported through the Dalrymple Bay Coal Terminal. Our joint venture Middlemount Mine is ramping up operations with shipments sent through both Dalrymple Bay Coal Terminal and the Abbot Point Coal Terminal in Queensland, Australia. In New South Wales, our primary ports for exporting metallurgical and thermal coal are at Port Kembla and Newcastle, which includes both the Port Waratah Coal Services terminal and the terminal operated by Newcastle Coal Infrastructure Group (NCIG) that opened in 2010. Our Australian mining operations sold approximately 74%, 71% and 69% of its tons into the seaborne coal markets for the years ended December 31, 2011, 2010 and 2009.

We are also currently pursuing a U.S. west coast port facility that will allow us to export Powder River Basin coal to Asian markets. In Australia, we are exploring potential participation in the development of the Wiggins Island Coal Export Terminal at Gladstone, Queensland, as well as proposed expansion projects at the Abbot Point Coal Terminal.

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, to benefit from long-term pricing for parts and to ensure security of supply.

Demand and lead times for certain surface and underground mining equipment and OTR tires has increased. Despite these market challenges, 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 relationships and long-term supply contracts we have with our suppliers. In addition, we continue to use our global leverage with major suppliers to ensure security of supply to meet the requirements of our growth plans. We have many well-established, strategic relationships with our key suppliers of goods and do not believe we are overly dependent on any of our individual 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 overly dependent on any of our individual service providers.

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Technical Innovation

We continue to emphasize the application of technical innovation to improve equipment performance and operating efficiencies. Development 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. Some examples of these efforts include the following:

- Ultra class haul trucks to increase overburden removal capacity and lower mining cost;
- Fleet management and vehicle diagnostics systems to enhance equipment availability;
- Expanded networking and server capacity to gather detailed information on both production and vehicle diagnostics to allow for real time alerts and long term analysis used to improve production and reduce downtime; and
- Longwall automation technology to allow for more efficient longwall mining.

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.

We also continue to advance new technologies to maximize safety. We are currently in process with a pilot program for a new proximity detection system at a section of one of our underground mines that is designed to automatically stop a continuous miner and coal hauler if a person is detected within the operating range. In addition, personnel tracking systems were deployed across all underground operations in the U.S. which can provide continuous real time locations of workers underground.

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 alternatives. Our principal U.S. competitors (listed alphabetically) are other large coal producers, including Alpha Natural Resources, Inc., Arch Coal, Inc., Cloud Peak Energy Inc., and CONSOL Energy Inc., which collectively accounted for approximately 40% of total U.S. coal production in 2010 (most recent publicly available data according to the National Mining Association's “2010 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, 2011, we had approximately 8,300 employees, which included approximately 5,600 hourly employees. As of such date, approximately 24% of our hourly employees were represented by organized labor unions and generated 7% of 2011 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 hourly production and engineering employees, including those employed through contract mining relationships. All the Australian mine sites have enterprise bargaining agreements. Additional information on labor relations is contained in Note 21 to our consolidated financial statements.

Working Capital

We generally fund our business operations through a combination of available cash and cash equivalents and operating cash flow. In addition, our revolving credit facility (Revolver) available under our senior unsecured credit facility entered into in 2010 (Credit Facility) 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.

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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 have 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 4. Mine Safety Disclosure and in Exhibit 95 to this Annual Report on Form 10-K, we provide additional details on how we monitor safety performance and MSHA compliance, as well as provide the mine safety disclosures required pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act).
Black Lung. Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees and last worked for the operator after July 1, 1973. Coal mine operators must also make payments to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. Historically, less than 7% of the miners currently seeking federal black lung benefits are awarded these benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

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

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

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

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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 created by the Coal Industry Retiree Health Benefit Act of 1992. 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), New Source Performance Standards (NSPS), 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. The EPA has also proposed a more stringent ozone standard but withdrew it last year; the ozone standard is due for reconsideration in 2013. Many of these programs and regulations have resulted in litigation which has not been completely resolved.

On July 6, 2011, the EPA finalized its final Cross State Air Pollution Rule (CSAPR) to address interstate transport of emissions from coal-based electrical generation plants. The rule, which was developed to replace CAIR and includes a supplemental rulemaking finalized on December 15, 2011, imposes state-by state budgets on nitrogen oxides and sulfur dioxide emissions from coal-based electrical generation plants in 23 states from Texas eastward (not including the New England states or Delaware) and provides for an allowance trading program to meet those budgets. While CSAPR has an initial compliance deadline of January 1, 2012, the rule was challenged and on December 30, 2011, the U.S. Court of Appeals for the District of Columbia stayed CSAPR and advised that the EPA is expected to continue administering CAIR until the pending challenges are resolved. Expedited briefing on the merits of the challenge is underway.

On December 16, 2011, the EPA issued the Mercury and Air Toxic Standards which imposes MACT emission limits on hazardous air emissions from new and existing coal-based electric generating plants. The rule also revised NSPS for nitrogen oxides, sulfur dioxides and particulate matter for coal-based electricity generating plants. The rule provides three years for compliance, or up to four years for existing sources if necessary. We believe that challenges to this rule are likely.

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.

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Because the Clean Air Act specifies that the prevention of significant deterioration (PSD) 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 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 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 is the subject of litigation.

In December 2010, the EPA announced a settlement with states and environmental groups that had filed litigation challenges to the 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. The EPA has not yet proposed these rules. 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 PSD 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.

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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 archaeological sites.

Mining Tenements and Environmental. In Queensland and New South Wales, the development of a mine requires both the grant of a right to impact the environment and an approval which authorizes the environmental impact. 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. Mining legislation is currently being harmonized across Australia with a January 1, 2013 target date. The harmonization process will be achieved first by developing core legislation that will be consistent across all of the states; the remainder of each states' legislation may be state specific. The finalized core legislation is expected to be completed by July 1, 2012.

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.

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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 CO2 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.

Carbon Pricing Framework. In the fourth quarter of 2011, the Australian government passed a legislative package that included a carbon pricing framework that commences July 1, 2012. The carbon price will initially be $23.00 Australian dollars per tonne of carbon dioxide equivalent emissions, escalated by 2.5% per year for inflation over a three year period. After June 30, 2015, the carbon price mechanism will transition to an emissions trading scheme. We believe that all of our Australian operations will be impacted by the fugitive emissions portion of the framework (defined as the methane and carbon dioxide which escapes into the atmosphere when coal is mined and gas is produced), which we estimate will initially average $2.00 to $3.25 Australian dollars per tonne of coal produced annually. Actual results will be dependent upon the volume of tons produced at each of our mining locations as the impact per tonne at our surface mines will generally be less than the impact per tonne at our underground mines. In addition, our Australian mines will be impacted by the phased reduction of the government's diesel fuel rebate to capture emissions from fuel combustion. Our North Goonyella, Wambo and Metropolitan mines will be eligible to apply for a portion of the government's approximately $1.3 billion Australian dollars of transition benefits that would provide assistance based on historical emissions intensity data to the most emissions-intensive coal mines over a six-year period.

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 undertaking steps to regulate greenhouse gas emissions pursuant to the Clean Air 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, ten northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont) entered into the Regional Greenhouse Gas Initiative (RGCI) in 2005, which is a mandatory cap-and-trade program to cap regional carbon dioxide emissions from power plants. In 2011, New Jersey announced its withdrawal from RGGI effective January 1, 2012. Six midwestern states (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) and one Canadian province have entered into the Midwestern Regional Greenhouse Gas Reduction Accord (MGGRA) to establish voluntary regional greenhouse gas reduction targets and develop a voluntary multi-sector cap-and-trade system to help meet the targets, though in the past year the group's website has been taken down and a senior official in the Midwestern Governors Association reported in February 2011 that the program was "effectively abandoned," according to the press. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces entered into the Western Climate Initiative (WCI) in 2008 to establish a voluntary regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. However, in November 2011 the WCI announced that six states had withdrawn from the WCI, leaving California and four Canadian provinces as the remaining members. As of early 2012, only California and Quebec have adopted greenhouse gas cap-and-trade regulations and intend to move forward with a regional trading program. Due to litigation and other delays, the regional trading program is not scheduled to commence until January 1, 2013. Other participants in WCI, RGGI and MGGRA have either left those organizations entirely or have joined the new North America 2050 organization which seeks to address energy and climate issues in other ways.

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In 2006, the California legislature approved legislation allowing the imposition of statewide caps on 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 started on January 1, 2012 with an enforceable compliance obligation beginning with the 2013 greenhouse gas emissions.

In the U.S., several states have enacted legislation requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power or that provide financial incentives to electricity suppliers for using renewable energy sources.

We participated in the DOE's Voluntary Reporting of Greenhouse Gases Program until its suspension in May 2011, 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 United Nations 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 at the Cancun meetings in late 2010 and initial steps toward that goal were taken and at the Durban meeting in late 2011. At the Durban meeting it was agreed that the Kyoto Protocol would have a second commitment period, from 2013 to 2017, but no further actions were agreed upon.

Australia's Parliament passed carbon pricing legislation in November 2011. The first three years of the program involve the imposition of a carbon tax commencing in July 2012, and a mandatory greenhouse gas emissions trading program commencing in 2015. However, the program is a central issue in current election debates.

Enactment of laws or passage of regulations by the U.S. or some of its states or by other countries regarding emissions from the mining of coal 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 by the U.S. or some of its states or by other countries regarding emissions from the combustion of coal 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 recent or 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, the state of commercial development and deployment of CCS technologies and the alternative markets for coal. 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 any 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, Peabody Plaza, 701 Market Street, Suite 900, St. Louis, Missouri 63101, attention: Investor Relations.

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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 strength of the global economy;
- the demand for electricity;
- the demand for steel, which may lead to price fluctuations in the periodic repricing of our metallurgical coal contracts;
- the global supply of thermal and metallurgical coal;
- weather patterns and natural disasters;
- competition within our industry and the availability and price of alternatives, including natural gas;
- 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 or mandating increased use of electricity from renewable energy sources;
- 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, current industry practice, and our practice, is to negotiate pricing for metallurgical coal contracts quarterly and seaborne thermal coal contracts annually.

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 2011, 91% of our worldwide sales volume was sold under long-term coal supply agreements. At January 31, 2012, 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 2011 production from continuing operations of 227.5 million tons. Contracts in backlog have remaining terms ranging up to 16 years.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. We may adjust these contract prices based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. We sometimes experience a reduction in coal prices in new long-term coal supply agreements replacing some of our expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer during the duration of specified events beyond the control of the affected party. Most of our 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 restrict the use or type of coal permissible at the customer’s plant or increases the price of coal beyond specified limits.

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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, 2011 we derived 23% of our total coal sales revenues from our five largest customers. Those five customers were supplied primarily from 24 coal supply agreements (excluding trading transactions) expiring at various times from 2012 to 2025. The contract contributing the greatest amount of annual revenue in 2011 was approximately $311 million, or approximately 4% of our 2011 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, particularly in developing countries such as 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, 2011, 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.

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

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

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

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

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

Our profitability or exposure to loss on transactions or relationships is dependent upon the reliability (including financial viability) and price of the third-party suppliers, our obligation to supply coal to customers in the event that weather, flooding, natural disasters or 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 trading and 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.

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Through our trading and hedging activities, we are also exposed to the nonperformance and credit risk with various counterparties, including exchanges and other financial intermediaries. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements, which could negatively impact our profitability and/or liquidity. In addition, some of our trading and brokerage activities include an increasing number of exchange-settled transactions, which exposes us to the margin requirements of the exchange for daily changes in the value of our positions. If there are significant and extended unfavorable price movements against our positions, or if there are future regulations that impose new margin requirements, position limits and capital charges, even if not directly applicable to us, our liquidity could be impacted.

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, 2011, we had approximately 8,300 employees, which included approximately 5,600 hourly employees. Approximately 24% of our hourly employees were represented by organized labor unions and generated 7% of 2011 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, 2011, we had $929.6 million of self bonding in place for our reclamation obligations. As of December 31, 2011, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of $1,214.6 million, of which $791.6 million was for post-mining reclamation, $76.1 million related to workers' compensation obligations, $104.7 million was for coal lease obligations and $242.2 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 Credit Facility and our 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, Credit Facility or our 2011 term loan facility (2011 Term Loan 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.

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

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

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

A number of laws, including in the U.S., 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 23 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.

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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. In certain locations, leases for oil, natural gas and coalbed methane reserves are located on, or adjacent to, some of our 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, 2011, we leased a total of 83,582 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 continue to explore ways to expand our international mining operations and global trading and brokerage platform. These efforts have included and are expected to include in the future such things as joint venture mining and exploration interests, such as partnering with other companies to utilize our mining experience for joint mine development, and sourcing coal from off-take arrangements to be sold through our Trading and Brokerage segment. Our international expansion increases our exposure to country risks and the effects of changes in currency exchange rates. Some of our international activities include expansion into developing countries where the economic strength, business practices and counterparty reputations may not be as well developed as in our U.S. or Australian operations. We are also challenged by various political risks, including political instability, the potential for expropriation of assets, costs associated with the repatriation of earnings and the potential for unexpected changes in regulatory requirements. Despite our efforts to mitigate these risks, our results of operations, financial position or cash flow could be adversely affected by these activities.

Risks Related to the Macarthur Acquisition

The extent to which we are able to successfully integrate the newly acquired Macarthur operations and successfully operate and develop the mine sites acquired from Macarthur will have a bearing on our future financial results.

The speed at which we integrate the Macarthur operations will have a direct bearing on the realization of anticipated synergies and benefits. Delays in optimizing the operations of the producing mines and in advancing the development and resource projects into operating mines and coal reserves could impact our future financial results.

We are more exposed to currency exchange rate fluctuations following completion of the Macarthur acquisition, and there is an increased proportion of assets, liabilities and expenses denominated in non-U.S. dollar currencies.

As a result of the completion of the Macarthur acquisition, our consolidated financial results are more exposed to currency exchange rate fluctuations, and an increased proportion of assets, liabilities and expenses are transacted in non-U.S. dollar currencies.

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We present our consolidated financial statements in U.S. dollars and will have a significant proportion of net assets and expenses denominated in the Australian dollar. Our consolidated financial results and capital ratios will, therefore, be sensitive to movements in foreign exchange rates. An appreciation of the Australian dollar relative to the U.S. dollar could have an adverse impact on our consolidated financial results.

If we fail to establish and maintain proper internal controls for the combined business, our ability to produce accurate financial statements or comply with applicable regulations could be impaired.

Prior to the acquisition, Macarthur was not subject to the reporting requirements of the Securities Exchange Act of 1934, as amended, or the Sarbanes-Oxley Act of 2002. As a subsidiary consolidated with our financial statements, Macarthur is subject to such rules and regulations. We are incorporating the internal controls and procedures of Macarthur into our internal control over financial reporting, and we expect to be able to perform an assessment of and report on internal control over financial reporting for the combined business for the year ending December 31, 2012. If we fail to establish and maintain proper internal controls for the combined business, our ability to produce accurate financial statements or comply with applicable regulations could be impaired.

Risks Associated with Our Indebtedness

We could be adversely affected by the failure of financial institutions to fulfill their commitments under our Credit Facility.

As of December 31, 2011, we had $1.5 billion of available ongoing borrowing capacity under the Revolver portion of 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, 2011, our total indebtedness was $6.7 billion, and we had $1.5 billion of available borrowing capacity under the Revolver portion of our Credit Facility, net of outstanding letters of credit. The indentures governing our Convertible Junior Subordinated Debentures (the Debentures) and the 7.375%, 7.875%, 6.50%, 6.25% and 6.00% Senior Notes (collectively our Senior Notes) do not limit the amount of indebtedness that we may issue.

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 the costs of borrowing under our existing credit facilities;
- 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 requirements;
- 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;
- making it more difficult to obtain surety bonds, letters of credit or other financing, particularly during periods in which credit markets are weak;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry;
- causing a decline in our credit ratings; 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 and result in amounts outstanding thereunder to be immediately due and payable.

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Any downgrade in our credit ratings could result in an increase in interest rates on our credit facilities, requirements to post additional collateral on derivative trading instruments, or the loss of trading counterparties for corporate hedging and commodity brokerage and trading.
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. Certain agreements governing our indebtedness 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 Facility and 2011 Term Loan Facility, and the indentures governing our Senior Notes and Debentures impose restrictions that may limit our operating and financial flexibility.
Our Credit Facility, 2011 Term Loan Facility, the indentures governing our 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 Facility, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined. The covenants also place limitations on our investments in joint ventures, unrestricted subsidiaries, indebtedness 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 Facility and 2011 Term Loan Facility. If we violate these covenants and are unable to obtain waivers from our lenders, our Credit Facility, our 2011 Term Loan Facility, our Senior Notes and our Debentures would be in default and the debt owing under such agreements could be accelerated. If our indebtedness is accelerated, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or on terms that are acceptable to us. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of our other debt or equity securities and may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.
The conversion of our Debentures may result in the dilution of the ownership interests of our existing stockholders.
If the conditions permitting the conversion of our Debentures are met and holders of the Debentures exercise their conversion rights, any conversion value in excess of the principal amount will be delivered in shares of our common stock. If any common stock is issued in connection with a conversion of our Debentures, our existing stockholders will experience dilution in the voting power of their common stock.
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.

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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 $1,121.5 million as of December 31, 2011, $68.4 million of which was a current liability. Net pension liabilities were $194.0 million as of December 31, 2011, $1.7 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 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. If we experience poor financial performance in asset markets in future years, we may be required to increase contributions.

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, 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.

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.

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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, 2011. An estimated 7.8 billion tons of our attributable proven and probable coal reserves are in the U.S. and 1.2 billion tons are in Australia. 32% of our Australian proven and probable coal reserves, or 380 million tons, are metallurgical coal with the remainder being thermal coal. 45% of our reserves, or 4.1 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 40% of these reserves and lease property containing the remaining 60%. Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emission allowance credits or blending higher sulfur coal with lower sulfur coal.
Below is a table summarizing the locations and reserves of our major operating regions.

		Proven and Probable Reserves as of December 31, 2011[1]		
Operating Regions	Locations	Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	2,719	926	3,645
Powder River Basin	Wyoming and Montana	67	2,791	2,858
Southwest	Arizona and New Mexico	805	274	1,079
Colorado	Colorado	46	182	228
Total United States		3,637	4,173	7,810
Australia	New South Wales	—	431	431
Australia	Queensland	—	770	770
Total Australia		—	1,201	1,201
Total Proven and Probable Coal Reserves		3,637	5,374	9,011

(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.

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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, 2011, we leased 11,536 acres of federal land in Colorado, 11,254 acres in Montana, 60,152 acres in Wyoming and 640 acres in New Mexico, for a total of 83,582 nationwide.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 64,785 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.

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

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

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

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

The following charts provide a summary, by mining complex, of production for the years ended December 31, 2011, 2010 and 2009, tonnage of coal reserves that is assigned to our operating mines, our property interest in those reserves and other characteristics of the facilities.

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PRODUCTION
(Tons in Millions)

Geographic Region / Mining Complex	Production Year Ended Dec. 31, 2011	Year Ended Dec. 31, 2010	Year Ended Dec. 31, 2009	Type of Coal	Sulfur Content [1] <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 [2]
Midwest:								
Bear Run	6.5	2.8	—	T	5	27	233	11,500
Gateway	3.3	3.2	3.3	T	—	—	9	11,000
Somerville Central	3.0	3.4	3.3	T	—	—	7	11,300
Francisco Underground	3.0	2.7	2.0	T	—	—	45	11,500
Willow Lake	2.2	2.9	3.4	T	—	—	24	12,100
Cottage Grove	1.9	2.1	2.1	T	—	—	22	12,500
Wild Boar	1.8	0.1	—	T	—	—	14	11,000
Viking - Corning Pit	1.5	1.5	1.6	T	—	—	4	11,500
Somerville North	1.4	2.0	2.0	T	—	—	4	10,600
Somerville South	1.2	1.7	1.8	T	—	—	6	11,100
Air Quality	1.2	1.1	1.6	T	21	2	31	11,300
Wildcat Hills Underground	1.0	0.8	0.7	T	—	—	21	12,200
Viking - Knox Pit (Closed in 2010)	—	1.7	2.0	T	—	—	—	NA
Farmersburg (Closed in 2010)	—	1.5	3.5	T	—	—	—	NA
Francisco Surface (Closed in 2009)	—	—	1.4	T	—	—	—	NA
Total	28.0	27.5	28.7		26	29	420	
Powder River Basin:								
North Antelope Rochelle	109.1	105.8	98.3	T	1,388	—	—	8,700
Caballo	24.1	23.5	23.3	T	827	127	22	8,300
Rawhide	15.0	11.2	15.8	T	263	66	4	8,300
Total	148.2	140.5	137.4		2,478	193	26	
Southwest:								
Kayenta	8.1	7.8	7.5	T	162	75	2	10,600
El Segundo	8.1	6.6	5.1	T	23	83	76	9,000
Lee Ranch	2.0	1.6	1.8	T	18	111	13	9,300
Total	18.2	16.0	14.4		203	269	91	
Colorado:								
Twentymile	7.7	7.7	7.8	T	39	—	—	11,300
Australia:								
Wilpinjong	10.9	9.6	8.4	T	—	186	—	11,200
Wambo [3]	5.8	6.6	4.1	T/P	207	—	—	12,200
North Goonyella / Eaglefield	2.2	3.2	2.5	M	113	—	—	12,900

Burton	2.1	2.5	2.0	T/M	47	—	—	12,700
Millennium	1.9	1.6	0.9	M	54	—	—	12,600
Metropolitan	1.8	1.6	1.5	M	38	—	—	12,600
Coppabella	0.4	—	—	P	33	—	—	12,700
Moorvale	0.3	—	—	T/M/P	16	—	—	12,100
Middlemount (4)	—	—	—	M/P	38	—	—	12,300
Total	25.4	25.1	19.4		546	186	—	
Total Continuing Operations	227.5	216.8	207.7		3,292	677	537	
Discontinued Operations	1.4	1.6	3.1		—	—	—	
Total Assigned	228.9	218.4	210.8		3,292	677	537	

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection

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ASSIGNED RESERVES [5]
AS OF DECEMBER 31, 2011

(Tons in Millions)		Attributable Ownership					100% Project Basis				
Geographic Region/Mining Complex	Interest	Proven and Probable Reserves	Owned	Leased	Surface	Underground	Proven and Probable Reserves	Owned	Leased	Surface	Underground
Midwest:											
Bear Run	100%	265	136	129	265	—	265	136	129	265	—
Gateway	100%	9	8	1	—	9	9	8	1	—	9
Somerville Central	100%	7	6	1	7	—	7	6	1	7	—
Francisco Underground	100%	45	8	37	—	45	45	8	37	—	45
Willow Lake	100%	24	14	10	—	24	24	14	10	—	24
Cottage Grove	100%	22	13	9	22	—	22	13	9	22	—
Wild Boar	100%	14	10	4	14	—	14	10	4	14	—
Viking - Corning Pit	100%	4	—	4	4	—	4	—	4	4	—
Somerville North	100%	4	1	3	4	—	4	1	3	4	—
Somerville South	100%	6	5	1	6	—	6	5	1	6	—
Air Quality	100%	54	3	51	—	54	54	3	51	—	54
Wildcat Hills Underground	100%	21	16	5	—	21	21	16	5	—	21
Total		475	220	255	322	153					
Powder River Basin:											
North Antelope Rochelle	100%	1,388	—	1,388	1,388	—	1,388	—	1,388	1,388	—
Caballo	100%	976	—	976	976	—	976	—	976	976	—
Rawhide	100%	333	—	333	333	—	333	—	333	333	—
Total		2,697	—	2,697	2,697	—					
Southwest:											
Kayenta	100%	239	—	239	239	—	239	—	239	239	—
El Segundo	100%	182	167	15	182	—	182	167	15	182	—
Lee Ranch	100%	142	122	20	142	—	142	122	20	142	—
Total		563	289	274	563	—					
Colorado:											
Twentymile	100%	39	8	31	—	39	39	8	31	—	39
Australia:											
Wilpinjong	100%	186	—	186	186	—	186	—	186	186	—
Wambo [3]	100%	207	—	207	73	134	207	—	207	73	134

North Goonyella / Eaglefield	100%	113	—	113	3	110	113	—	113	3	110
Burton	100%	47	—	47	47	—	47	—	47	47	—
Millennium	100%	54	—	54	54	—	54	—	54	54	—
Metropolitan	100%	38	—	38	—	38	38	—	38	—	38
Coppabella	73.3%	33	—	33	33	—	45	—	45	45	—
Moorvale	73.3%	16	—	16	16	—	22	—	22	22	—
Middlemount (4)	50.0%	38	—	38	38	—	75	—	75	75	—
Total		732	—	732	450	282					
Total Assigned		4,506	517	3,989	4,032	474					

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES
AS OF DECEMBER 31, 2011
(Tons in Millions)

	Attributable Ownership					100% Project Basis				
	Total Tons		Proven and Probable			Total Tons		Proven and Probable		
Coal Seam Location	Assigned	Unassigned	Reserves	Proven	Probable	Assigned	Unassigned	Reserves	Proven	Probable
Midwest:										
Illinois	76	2,232	2,308	1,186	1,122	76	2,232	2,308	1,186	1,122
Indiana	399	442	841	614	227	399	442	841	614	227
Kentucky	—	496	496	264	232	—	496	496	264	232
Total	475	3,170	3,645	2,064	1,581					
Powder River Basin:										
Montana	—	161	161	157	4	—	161	161	157	4
Wyoming	2,697	—	2,697	2,620	77	2,697	—	2,697	2,620	77
Total	2,697	161	2,858	2,777	81					
Southwest:										
Arizona	239	—	239	239	—	239	—	239	239	—
New Mexico	324	516	840	759	81	324	516	840	759	81
Total	563	516	1,079	998	81					
Colorado	39	189	228	146	82	39	189	228	146	82
Australia:										
New South Wales	431	—	431	368	63	431	—	431	368	63
Queensland (6)	301	469	770	675	95	356	484	840	726	114
Total	732	469	1,201	1,043	158					
Total Proven and Probable	4,506	4,505	9,011	7,028	1,983					

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ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2011
(Tons in Millions)

	Attributable Ownership				100% Project Basis			
	Reserve Control		Mining Method		Reserve Control		Mining Method	
Coal Seam Location	Owned	Leased	Surface	Underground	Owned	Leased	Surface	Underground
Midwest:								
Illinois	1,926	382	62	2,246	1,926	382	62	2,246
Indiana	489	352	427	414	489	352	427	414
Kentucky	304	192	89	407	304	192	89	407
Total	2,719	926	578	3,067				
Powder River Basin:								
Montana	67	94	161	—	67	94	161	—
Wyoming	—	2,697	2,697	—	—	2,697	2,697	—
Total	67	2,791	2,858	—				
Southwest:								
Arizona	—	239	239	—	—	239	239	—
New Mexico	805	35	813	27	805	35	813	27
Total	805	274	1,052	27				
Colorado	46	182	—	228	46	182	—	228
Australia:								
New South Wales	—	431	259	172	—	431	259	172
Queensland (6)	—	770	641	129	—	840	709	131
Total	—	1,201	900	301				
Total Proven and Probable	3,637	5,374	5,388	3,623				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2011
(Tons in Millions)

		Attributable Ownership Sulfur Content (1)			100% Project Basis Sulfur Content (1)			
		<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	As
Coal Seam Location	Type of Coal	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Received Btu per Pound (2)
Midwest:								
Illinois	T	—	—	2,308	—	—	2,308	10,300
Indiana	T	26	38	777	26	38	777	10,300
Kentucky	T	—	1	495	—	1	495	10,900
Total		26	39	3,580				
Powder River Basin:								
Montana	T	9	121	31	9	121	31	8,600
Wyoming	T	2,478	193	26	2,478	193	26	8,700
Total		2,487	314	57				
Southwest:								
Arizona	T	162	75	2	162	75	2	10,900
New Mexico	T	157	402	281	157	402	281	9,400
Total		319	477	283				
Colorado	T	222	—	6	222	—	6	10,700
Australia:								
New South Wales	T/M/P	245	186	—	245	186	—	11,800
Queensland (6)	T/M/P	770	—	—	840	—	—	11,700
Total		1,015	186	—				
Total Proven and Probable		4,069	1,016	3,926				

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection

(1) 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.

(2) 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.

(3) 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.

(4) Middlemount represents our 50.0% interest in Middlemount Coal Pty Ltd., which owns the Middlemount Mine in Queensland, Australia that was acquired as part of the Macarthur acquisition.

(5) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2011. 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.

(6) Unassigned reserves in Queensland includes approximately 198 million tons of reserves held for sale associated with our Wilkie Creek Mine.

Item 3. Legal Proceedings.

See Note 23 to our consolidated financial statements for a description of our pending legal proceedings, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures.

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 employees to provide a safe and healthy work 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 recurrence. As part of our training, we collaborate with MSHA and other government agencies to identify and test emerging safety technologies. We also believe personal accountability is key; every employee commits to our safety goals and governing principles. Managers, frontline supervisors and employees are held responsible for their safety and the safety of other employees. 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 employees. We have installed communications and tracking systems at our U.S. underground mines, which allow persons on the surface to determine the location of and communicate with all persons underground. In addition, we are testing a proximity detection system at a section of one of our mines, which is designed to automatically stop mining equipment if a person is detected within the operating range of a continuous miner or coal hauler.

The incidence rate is a measure of safety performance, which is tracked through our safety tracking system. The incidence rate is computed as the number of injuries, MSHA reportable injury degree codes 1 through 6, multiplied by 200,000, divided by employee hours worked [(number of reportable incidents X 200,000) ÷ employee hours worked]. Since MSHA is a branch of the U.S. Department of Labor, its jurisdiction applies only to our U.S. mines. However, we also track incidence rate for our Australian mines to measure safety performance on the same basis as our U.S. mines. The following table reflects our incidence rates (as of February 23, 2012) and the comparable MSHA incidence rates:

	Year Ended December 31,		
	2011	2010	2009
U.S.	1.37	1.98	2.16
Australia(1)	2.77	4.03	4.43
Total Peabody Energy Corporation(1)	1.92	2.71	2.92
MSHA (U.S. coal mines)(2)	3.69	3.93	4.14

(1) Results exclude Macarthur for all periods presented. Macarthur's incidence rate for the acquisition date through December 31, 2011 was 1.54. Results for all periods presented include our Wilkie Creek Mine, which is held for sale as of December 31, 2011.

(2) 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 U.S. coal mines, excluding the impact of office workers (“All Incidence Rate”). The 2011 MSHA all incidence rate of 3.69 reflected above represents preliminary results for January-December 2011 (latest data available) as published by MSHA as of February 23, 2012.

We monitor MSHA compliance using violations per inspection day (in the U.S. only), which is calculated as the total count of violations per five hour MSHA inspector day. For the years ended December 31, 2011, 2010 and 2009, our U.S. violations per inspection day were 0.81, 0.84 and 1.11, respectively.

The historical incidence rates and violations per inspection day may be adjusted over time to reflect the final resolution of incidents, citations and orders by MSHA. The impact of these adjustments, which has not historically resulted in significant changes to the results originally reported, is reflected in the MSHA database. The MSHA incidence rates disclosed above reflect the rates in the MSHA Mine Injury and Worktime Operators report, which are not updated by MSHA once a final report has been issued.

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K is included in Exhibit 95 to this Annual Report on Form 10-K.

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Executive Officers of the Company

Set forth below are the names, ages as of February 17, 2012 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	57	Chairman and Chief Executive Officer, Director
Richard A. Navarre	51	President and Chief Commercial Officer
Michael C. Crews	44	Executive Vice President and Chief Financial Officer
Sharon D. Fiehler	55	Executive Vice President and Chief Administrative Officer
Eric Ford	57	Executive Vice President and Chief Operating Officer
Jeane L. Hull	57	Executive Vice President - Technical Services
Alexander C. Schoch	57	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 Deputy Chairman of the Coal Industry Advisory Board of the International Energy Agency. He is a member of the National Coal Council; The Business Council; Business Roundtable; 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 Board of Directors of the Regional Chamber and Growth Association of St. Louis; and a member of the Foreign Policy Association. He is a Director of the United Way of Greater St. Louis; Vice Chair of CEOs Against Cancer; and a member of the Cardinal Glennon - Bob Costas Benefit Committee. He is Treasurer of the Missouri Historical Society; a member of Financial Executives International; 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, a Master of Business Administration (MBA) degree from Washington University in St. Louis and is a Certified Public Accountant in the state of Missouri.

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 Deputy Chair and 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 a member of the Chancellor's Council of the University of Missouri - St. Louis. She is also a member of the Missouri Women's Forum and the St. Louis Forum.

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Eric Ford was named our Executive Vice President and Chief Operating Officer in March 2007. Mr. Ford has 40 years of extensive international management, operating and engineering experience and, prior to joining us, 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 serves on the board of directors of Compass Minerals International, Inc. Mr. Ford 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.

Jeane L. Hull was named our Executive Vice President - Technical Services in March 2011. She joined us in March 2007 as the Senior Vice President of Engineering and Technical Services, and then served as Group Executive - Powder River Basin and Southwest from June 2008 to March 2011. Prior to joining us, Ms. Hull served as Chief Operating Officer of Kennecott Utah Copper, a subsidiary of Rio Tinto. She held numerous management, engineering and operations positions with Rio Tinto and affiliates and also spent 12 years with Mobil Mining and Minerals and Mobil Chemical Company. A registered professional engineer, Ms. Hull graduated from the South Dakota School of Mines and Technology with a Bachelor of Science degree in Civil Engineering. She holds a MBA from Nova University in Florida.

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 17, 2012, there were 1,386 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
2011			
First Quarter	$73.73	$57.44	$0.085
Second Quarter	73.95	52.44	0.085
Third Quarter	61.85	33.84	0.085
Fourth Quarter	47.81	30.60	0.085
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

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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 26, 2012, payable on March 1, 2012, to stockholders of record on February 9, 2012. 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. While no such share repurchases were made in 2011, 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 share repurchase program does not have an expiration date and may be discontinued at any time. Through December 31, 2011, 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 share repurchase program.

The following table summarizes all share repurchases for the three months ended December 31, 2011:

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, 2011	52,685	$45.27	—	$700.4
November 1 through November 30, 2011	4,157	36.06	—	700.4
December 1 through December 31, 2011	—	—	—	700.4
Total	56,842	$44.60	—	

(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 2011, 2010 and 2009 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 25 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.

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On October 26, 2011, we acquired Macarthur. Our results of operations include Macarthur's results of operations from the date of acquisition. Macarthur's results are reflected in our Australian Mining Segment. See Note 2 to our consolidated financial statements for additional details.

We have derived the selected historical financial data as of and for the years ended December 31, 2011, 2010, 2009, 2008 and 2007 from our audited financial statements. You should read the following table in conjunction with the financial statements, the related notes to those financial statements and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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,				
	2011	2010	2009	2008	2007
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	$7,974.4	$6,739.9	$5,847.0	$6,335.6	$4,422.2
Costs and expenses	6,381.0	5,385.5	5,024.6	5,053.3	3,830.6
Operating profit	1,593.4	1,354.4	822.4	1,282.3	591.6
Interest expense, net	219.7	212.4	193.0	217.1	228.8
Income from continuing operations before income taxes	1,373.7	1,142.0	629.4	1,065.2	362.8
Income tax provision (benefit)	363.2	315.4	186.2	159.8	(73.1)
Income from continuing operations, net of income taxes	1,010.5	826.6	443.2	905.4	435.9
(Loss) income from discontinued operations, net of income taxes	(64.2)	(24.4)	19.8	53.7	(174.4)
Net income	946.3	802.2	463.0	959.1	261.5
Less: Net (loss) income attributable to noncontrolling interests	(11.4)	28.2	14.8	6.2	(2.3)
Net income attributable to common stockholders	$957.7	$774.0	$448.2	$952.9	$263.8
Basic earnings per share from continuing operations	$3.77	$2.97	$1.60	$3.32	$1.65
Diluted earnings per share from continuing operations	$3.76	$2.93	$1.59	$3.30	$1.62
Weighted average shares used in calculating basic earnings per share	269.1	267.0	265.5	268.9	264.1
Weighted average shares used in calculating diluted earnings per share	270.3	269.9	267.5	270.7	268.6
Dividends declared per share	$0.340	$0.295	$0.250	$0.240	$0.240
Other Data					
Tons sold	250.6	244.2	241.3	252.5	233.1
Net cash provided by (used in) continuing operations:					
Operating activities	$1,658.1	$1,116.7	$1,044.9	$1,317.0	$462.6
Investing activities	(3,745.5)	(694.5)	(407.4)	(412.6)	(535.8)
Financing activities	1,678.5	(77.1)	(104.6)	(498.0)	37.4
Adjusted EBITDA	2,128.7	1,838.7	1,262.8	1,728.2	958.2
Balance Sheet Data (at period end)					
Total assets	$16,733.0	$11,363.1	$9,955.3	$9,695.6	$9,082.3
Total long-term debt (including capital leases)	6,657.5	2,750.0	2,752.3	2,793.6	2,909.0
Total stockholders' equity	5,515.8	4,689.3	3,755.9	3,119.5	2,735.3

Adjusted EBITDA is calculated as follows (unaudited):

	Year Ended December 31,				
	2011	2010	2009	2008	2007
		(Dollars in millions)			
Income from continuing operations, net of income taxes	$1,010.5	$826.6	$443.2	$905.4	$435.9
Income tax provision (benefit)	363.2	315.4	186.2	159.8	(73.1)
Depreciation, depletion and amortization	482.2	437.1	400.5	397.8	342.9
Asset retirement obligation expense	53.1	47.2	39.9	48.1	23.7
Interest expense, net	219.7	212.4	193.0	217.1	228.8
Adjusted EBITDA	$2,128.7	$1,838.7	$1,262.8	$1,728.2	$958.2

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. We own interests in 30 coal mining operations, including a majority interest in 29 coal operations located in the U.S. and Australia and a 50% equity interest in the Middlemount Mine in Australia. We also own an equity interest in a joint venture mining operation in Venezuela. In 2011, we produced 227.5 million tons of coal from continuing operations and sold 250.6 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 segment consist of our Powder River Basin, Southwest and Colorado operations. Our Midwestern U.S. Mining segment 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.

On October 26, 2011, we acquired Macarthur. Our results of operations include Macarthur's results of operations from the date of acquisition. Macarthur's results are reflected in our Australian Mining Segment.

In the U.S., we typically sell coal to utility customers under long-term contracts (those with terms longer than one year). Our Australia Mining operations are primarily export focused with customers spread across several countries, while a portion of our coal is sold to Australian steel producers and power generators. Generally, Australian revenues from individual countries vary year by year based on the demand for electricity, the demand for steel, the strength of the global economy and several other factors including those specific to each country. Historically in Australia Mining operations, 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.

During 2011, approximately 91% of our worldwide sales (by volume) were under long-term contracts. For the year ended December 31, 2011, 82% of our total sales (by volume) were to U.S. electricity generators, 15% were to customers outside the U.S. and 3% 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, Btu Conversion activities, as well as the optimization of our coal reserve and real estate holdings.

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, including CCS.

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As discussed more fully in Item 1A. “Risk Factors,” our results of operations in the near-term could be negatively impacted by weather conditions, cost of competing fuels, availability of transportation for coal shipments, labor relations, unforeseen geologic conditions or equipment problems at mining locations and by the pace 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 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 in response to changes in market demand.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Summary

Global coal consumption rose to an estimated 7.7 billion tonnes in 2011 driven by increased coal use in China, India and other developing Asian nations. Global seaborne demand rose an estimated 6% and exceeded 1 billion tonnes, led by an increase in thermal demand to supply new coal-fueled electricity generation brought on line in 2011. Global steel production grew an estimated 7% while China and India's coal-fueled electricity generation rose 14% and 9%, respectively, in 2011.

In the U.S., coal markets have been impacted by a weak economy, low electricity generation and depressed near-term natural gas prices. U.S. coal electricity generation declined an estimated 6% in 2011 while U.S. coal exports increased 28% to an estimated 108 million tons.

Our revenues increased compared to the prior year by $1,234.5 million and Segment Adjusted EBITDA increased over the prior year by $372.8 million, led by higher average prices in all regions and increased volume in the U.S. Income from continuing operations, net of income taxes, increased compared to the prior year by $183.9 million due to the increase in Segment Adjusted EBITDA discussed above, partially offset by lower Corporate and Other Adjusted EBITDA and increased income taxes, depreciation, depletion and amortization, and interest expense.

We ended the year with total available liquidity of $2.3 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, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease)	
	2011	2010	Tons	%
	(Tons in millions)			
Western U.S. Mining	173.6	163.8	9.8	6.0 %
Midwestern U.S. Mining	30.3	29.7	0.6	2.0 %
Australian Mining	25.3	25.3	—	— %
Trading and Brokerage	21.4	25.4	(4.0)	(15.7)%
Total tons sold	250.6	244.2	6.4	2.6 %

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Revenues

The following table presents revenues for the years ended December 31, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2011	2010	$	%
	(Dollars in millions)			
Western U.S. Mining	$2,900.4	$2,706.3	$194.1	7.2 %
Midwestern U.S. Mining	1,481.1	1,320.6	160.5	12.2 %
Australian Mining	3,080.7	2,399.9	680.8	28.4 %
Trading and Brokerage	475.1	291.1	184.0	63.2 %
Corporate and Other	37.1	22.0	15.1	68.6 %
Total revenues	$7,974.4	$6,739.9	$1,234.5	18.3 %

The increase in Australian Mining operations' revenues compared to the prior year was driven by a higher weighted average sales price of 26.5%, led by increased pricing for seaborne metallurgical and thermal coal due to a combination of increased global coal demand and coal supply constraints resulting from weather impacts in early 2011. In 2011, Macarthur operations contributed revenues of $152.9 million on 0.9 million tons sold. These favorable impacts were partially offset by lower metallurgical volumes due to a third quarter roof fall and recovery of longwall operations at our North Goonyella Mine and flooding in Queensland that began in late 2010 that lowered production and shipments in the first quarter of 2011. Metallurgical coal sales totaled 9.3 million tons in 2011 as compared to 9.8 million tons in 2010.

Western U.S. Mining operations' revenues were higher compared to the prior year as volumes and the weighted average sales price were above the prior year. The volume increase of 6.0% was led by increased shipments from our Powder River Basin region due to increased customer demand. Our weighted average sales price rose modestly compared to the prior year (1.2%) as favorable contract pricing in our Southwest region was partially offset by lower pricing in the Powder River Basin region due to a combination of sales mix and the expiration of some higher-priced, long-term contracts signed before the economic recession in the 2008 and 2009 timeframe.

Trading and Brokerage revenues were higher compared to the prior year due to an increase in export volumes, which carry higher prices, and higher overall coal market pricing on our brokerage activity, partially offset by lower domestic volumes.

In the Midwestern U.S. Mining segment, revenue improvements compared to the prior year were due to a higher weighted average sales price of 9.8% driven by favorable contracts signed in recent years. Volumes were also higher (2.0%) due to incremental contributions from our Bear Run Mine (which commenced operations in May 2010) and Wild Boar Mine (which commenced operations in December 2010).

Segment Adjusted EBITDA

The following table presents segment Adjusted EBITDA for the years ended December 31, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2011	2010	$	%
		(Dollars in millions)		
Western U.S. Mining	$766.0	$816.7	$(50.7)	(6.2)%
Midwestern U.S. Mining	408.9	322.1	86.8	26.9 %
Australian Mining	1,194.3	977.4	216.9	22.2 %
Trading and Brokerage	197.0	77.2	119.8	155.2 %
Total Segment Adjusted EBITDA	$2,566.2	$2,193.4	$372.8	17.0 %

Australian Mining operations' Adjusted EBITDA increased compared to the prior year due to a higher weighted average sales price ($742.6 million), partially offset by lower production and higher costs at our North Goonyella Mine due to a roof fall and recovery of longwall operations ($234.7 million), an unfavorable foreign currency impact on operating costs, net of hedging ($135.8 million), cost escalations for labor, materials and services ($64.0 million), increased royalty expense associated with our higher-priced coal shipments ($54.1 million) and lower volumes ($38.1 million), excluding the impact of the North Goonyella roof fall discussed above.

Trading and Brokerage Adjusted EBITDA increased primarily due to higher margins on our brokerage activity due to higher prices as discussed above.

Midwestern U.S. Mining operations' Adjusted EBITDA increased compared to the prior year due to a higher weighted average sales price ($112.5 million), partially offset by increased labor ($17.7 million) and materials and services costs ($12.4 million) related primarily to compliance measures at our underground mines.

Western U.S. Mining operations' Adjusted EBITDA decreased as compared to the prior year due to higher volume-driven labor ($39.1 million) and materials and services costs ($31.3 million), increased equipment repairs and maintenance costs ($33.1 million), a provision related to litigation recorded in the second quarter of 2011 ($24.5 million), and increased commodity costs, net of hedging ($16.1 million). The above decreases to the segment's Adjusted EBITDA were partially offset by increased volumes ($88.0 million) and a higher weighted average sales price ($41.6 million) 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, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease) to Income	
	2011	2010	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$2,566.2	$2,193.4	$372.8	17.0 %
Corporate and Other Adjusted EBITDA[1]	(437.5)	(354.7)	(82.8)	23.3 %
Depreciation, depletion and amortization	(482.2)	(437.1)	(45.1)	10.3 %
Asset retirement obligation expense	(53.1)	(47.2)	(5.9)	12.5 %
Interest expense	(238.6)	(222.0)	(16.6)	7.5 %
Interest income	18.9	9.6	9.3	96.9 %
Income from continuing operations before income taxes	$1,373.7	$1,142.0	$231.7	20.3 %

(1) Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income (loss) from our joint ventures, certain asset sales, resource management costs and revenues, coal royalty expense, costs associated with past mining activities, expenses related to our other commercial activities such as generation development and Btu Conversion costs and provisions for certain litigation.

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

Corporate and Other Adjusted EBITDA reflects higher expenses compared to the prior year due primarily to the following:

- Higher current year expenses in support of our international expansion, acquisition activity and other growth initiatives, including $85.2 million of expenses associated with the acquisition of Macarthur; and
- Lower current year results from equity affiliates ($17.5 million) due to current year losses associated with our joint venture arrangement in Australia ($7.3 million) and earnings recognized in the prior year associated with transaction services related to our Mongolian joint venture ($10.0 million); partially offset by
- Increased gains on disposal or exchange of assets ($46.9 million) driven by current year non-cash exchanges of coal reserves in Kentucky and coal reserves and surface lands in Illinois for coal reserves in West Virginia ($37.7 million) and current year gains of $31.7 million associated with sales of non-strategic coal reserves in Kentucky and Illinois, partially offset by prior year gains associated with non-cash exchanges of coal reserves in Kentucky and coal reserves

and surface lands in Illinois for coal reserves in West Virginia ($23.7 million); and

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- A current year gain associated with the receipt of a $14.6 million project development fee related to our involvement in Prairie State.

Depreciation, depletion and amortization expense increased compared to the prior year primarily driven by additional expense associated with the assets acquired in the Macarthur acquisition.

Interest expense increased $16.6 million over the prior year due primarily to current year acquisition related interest expense of $45.3 million, which includes $29.1 million of expense related to ongoing financing and $16.2 million of expense for bridge financing, partially offset by costs in the prior year of $9.3 million associated with the refinancing of our five-year Credit Facility and $8.4 million of charges associated with the extinguishment 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, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease) to Income	
	2011	2010	$	%
	(Dollars in millions)			
Income from continuing operations before income taxes	$1,373.7	$1,142.0	$231.7	20.3 %
Income tax provision	363.2	315.4	47.8	15.2 %
Income from continuing operations, net of income taxes	1,010.5	826.6	183.9	22.2 %
Loss from discontinued operations, net of income taxes	(64.2)	(24.4)	(39.8)	163.1 %
Net income	946.3	802.2	144.1	18.0 %
Net (loss) income attributable to noncontrolling interests	(11.4)	28.2	(39.6)	(140.4)%
Net income attributable to common stockholders	$957.7	$774.0	$183.7	23.7 %

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.

The provision for income taxes increased compared to the prior year due to higher current year earnings ($81.1 million), a change in valuation allowances ($44.1 million) related primarily to alternative minimum tax credits released in the prior year and higher current year state income taxes ($17.1 million). The increases to income tax expense were partially offset by lower current year foreign earnings repatriation expense ($76.9 million) and a current year benefit of $0.9 million associated with the remeasurement of non-U.S. tax accounts as compared to remeasurement expense of $47.9 million in the prior year as the Australian exchange rate decreased against the U.S. dollar in the current year as compared to an increase in the prior year, as set forth in the table below.

	December 31,			Rate Change	
	2011	2010	2009	2011	2010
Australian dollar to U.S. dollar exchange rate	$1.0156	$1.0163	$0.8969	$(0.0007)	$0.1194

Loss from discontinued operations for 2011 reflects a loss of $64.2 million as compared to a loss of $24.4 million in the prior year due primarily to higher current year losses associated with assets held for sale in our Australian Mining operations segment.

Net loss attributable to noncontrolling interests in the current year was driven by ArcelorMittal Mining Australasia B.V.'s interest in Macarthur from the acquisition and control date of October 26, 2011 to the date we acquired ArcelorMittal Mining Australasia B.V. on December 21, 2011.

Other

The net fair value of our foreign currency hedges decreased from an asset of $640.1 million at December 31, 2010 to an asset of $490.6 million at December 31, 2011 primarily due to the realization of hedge gains in 2011. This decrease is reflected in “Other current assets” and “Investments and other assets” in the consolidated balance sheets.

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The fair value of our coal trading positions, before the application of margin, designated as cash flow hedges of forecasted sales changed from a liability of $174.2 million at December 31, 2010 to a liability of $22.4 million at December 31, 2011 due to favorable market price movements on our positions held and realization of completed transactions.

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 from April to December 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 2010 revenues increased compared to 2009 by $892.9 million and Segment Adjusted EBITDA increased over 2009 by $586.1 million, led by higher Australian pricing and sales volumes in 2010 despite unfavorable weather-related volume impacts that occurred late in 2010.

Income from continuing operations, net of income taxes, increased compared to 2009 by $383.4 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 2010 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	25.3	20.0	5.3	26.5 %
Trading and Brokerage	25.4	29.4	(4.0)	(13.6)%
Total tons sold	244.2	241.3	2.9	1.2 %

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Revenues

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

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2010	2009	$	%
	(Dollars in millions)			
Western U.S. Mining	$2,706.3	$2,612.6	$93.7	3.6%
Midwestern U.S. Mining	1,320.6	1,303.8	16.8	1.3%
Australian Mining	2,399.9	1,512.6	887.3	58.7%
Trading and Brokerage	291.1	391.0	(99.9)	(25.5)%
Corporate and Other	22.0	27.0	(5.0)	(18.5)%
Total revenues	$6,739.9	$5,847.0	$892.9	15.3%

The increase in Australian Mining operations' revenues was driven by a higher weighted average sales price of 25.4%, led by increased pricing on seaborne metallurgical and thermal coals and a higher mix of metallurgical coal shipments. Volumes also increased in 2010 (26.5%) driven by increased demand for metallurgical coal (metallurgical coal shipments of 9.8 million tons were 2.9 million tons, or 42.0%, greater than 2009). 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 2009 customer destocking of inventory and lower capacity utilization at steel customers.

Western U.S. Mining operations' revenues increased compared to 2009 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	977.4	410.5	566.9	138.1%
Trading and Brokerage	77.2	193.4	(116.2)	(60.1)%
Total Segment Adjusted EBITDA	$2,193.4	$1,607.3	$586.1	36.5%

Our Australian Mining segment benefited from a higher weighted average sales price ($408.3 million) and increased volumes ($134.0 million) as discussed above, and productivity improvements at our North Goonyella and Wambo underground mines along with fewer longwall move days in 2010 ($116.0 million). Partially offsetting the above improvements were net higher adverse weather impacts 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).

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Western U.S. Mining operations' Adjusted EBITDA increased compared to 2009 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 2010 ($10.0 million), partially offset by 2009 customer contract termination and restructuring agreements ($27.8 million) and increased commodity costs in the 2010 ($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	$2,193.4	$1,607.3	$586.1	36.5 %
Corporate and Other Adjusted EBITDA[1]	(354.7)	(344.5)	(10.2)	3.0 %
Depreciation, depletion and amortization	(437.1)	(400.5)	(36.6)	9.1 %
Asset retirement obligation expense	(47.2)	(39.9)	(7.3)	18.3 %
Interest expense	(222.0)	(201.1)	(20.9)	10.4 %
Interest income	9.6	8.1	1.5	18.5 %
Income from continuing operations before income taxes	$1,142.0	$629.4	$512.6	81.4 %

(1) Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income (loss) from our joint ventures, certain asset sales, resource management costs and revenue, coal royalty expense, costs associated with past mining obligations, expenses related to our other commercial activities such as generation development and Btu Conversion costs and provision for certain litigation.

Income from continuing operations before income taxes was higher compared to 2009 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 an 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 2009 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.
- Depreciation, depletion and amortization: higher compared to 2009 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.

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Net Income Attributable to Common Stockholders

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

	Year Ended December 31,		Increase (Decrease) to Income	
	2010	2009	$	%
	(Dollars in millions)			
Income from continuing operations before income taxes	$1,142.0	$629.4	$512.6	81.4 %
Income tax provision	315.4	186.2	129.2	69.4 %
Income from continuing operations, net of income taxes	826.6	443.2	383.4	86.5 %
(Loss) income from discontinued operations, net of income taxes	(24.4)	19.8	(44.2)	(223.2)%
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 2009 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 earnings ($179.4 million) and income tax resulting from foreign earnings repatriation ($84.5 million), partially offset by
- A change in the valuation allowance ($46.0 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 2009 compared to 2010 ($26.5 million) as set forth in the table below, the favorable rate difference resulting from higher foreign generated income in 2010 ($41.1 million), and lower expense in 2010 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

(Loss) income from discontinued operations for 2010 reflects a loss of $24.4 million as compared to income of $19.8 million in 2009. 2010 and 2009 includes results of operations related to assets held for sale in Australia and the Midwestern U.S. 2009 also includes a coal excise tax refund receivable of approximately $35 million recorded in 2009 and a $10.0 million loss on disposal of our Australian Chain Valley Mine.

Other

The net 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. The increase is reflected in “Other current assets” and “Investments and other assets” in the consolidated balance sheets.

Outlook

Our near-term outlook is intended to address the next 12-24 months, with any subsequent periods addressed in our long-term outlook.

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Near-Term Outlook

Global coal consumption rose in 2011 to an estimated 7.7 billion tonnes, driven by increased coal use in China, India and other developing Asian nations. Global seaborne demand rose an estimated 6% and exceeded 1 billion tonnes, led by an increase in thermal demand to supply approximately 81 gigawatts of new coal-fueled electricity generation brought on line in 2011. In the U.S., coal markets have been marked by a weak economy, low electricity generation and depressed near-term natural gas prices. U.S. coal electricity generation declined an estimated 6% in 2011 driven by more mild weather as compared to the prior year as well as some displacement from hydro and natural gas, while U.S. coal exports increased 28% to an estimated 108 million tons.

- The International Monetary Fund's January 2012 World Economic Outlook estimates global economic activity, as measured by gross domestic product (GDP), will grow 3.3% in 2012 and 3.9% in 2013, led by China and India. China's GDP is projected to grow 8.2% in 2012 and 8.8% in 2013. India, the world's second fastest growing economy, is projected to grow 7.0% in 2012 and 7.3% in 2013.
- According to the World Steel Association, global steel use is expected to increase 5.4% in 2012, with China expected to grow its steel use by 6.0%.

Prices for global seaborne metallurgical and thermal coal have come down from record highs during 2011, though recent settlements have still been higher than historical averages. Metallurgical coal prices for high quality hard coking coal and LV PCI settled at $235 and $171 per tonne, respectively, for quarterly contracts commencing January 2012. We have settled first quarter metallurgical coal shipments in line with these recent settlements, with essentially all remaining 2012 metallurgical coal production unpriced. We expect near-term macroeconomic movements to dictate quarterly pricing for the remainder of 2012 and we are targeting total 2012 metallurgical coal sales of approximately 14 to 15 million tons.

Seaborne thermal coal originating from Newcastle, Australia, has been settled for annual contracts beginning in January 2012 at $116 per tonne. As of January 24, 2012, we had 40% to 50% of 2012 seaborne thermal coal volumes available for pricing in Australia and we are targeting 2012 Australian thermal exports of 12 to 13 million tons.

Looking at U.S. markets, the Energy Information Administration's (EIA) February 2012 Short-Term Energy Outlook projects 2012 U.S. electric power coal consumption to decline by approximately 2%. U.S. coal production is also expected to decline by 2%, despite slight production expansion in the Western region. U.S. producers will look to increase exports as domestic markets remain weak relative to historic levels and global seaborne thermal markets provide growing sales opportunities.

The coal-fueled electric power generation decline in 2012 is projected to be primarily driven by depressed near-term natural gas prices that are resulting in elevated levels of coal-to-gas switching, with the largest impact projected to be on Central Appalachian coal supply. If coal-to-gas switching lasts for a prolonged period during 2012 due to significantly depressed natural gas prices, there may be more substantial unfavorable impacts to all coal supply regions, including the Powder River Basin. We continually adjust our production levels in response to changes in market demand.

We are targeting our U.S. volumes in 2012 to be on par with prior year levels and are fully committed on pricing. As of January 24, 2012, we had 45% to 55% of planned U.S. production unpriced for 2013. As a result of the current weak U.S. coal market environment, some customers may attempt to delay and/or cancel portions of contracted 2012 volumes. Our coal supply agreement contractual terms and conditions provide support for us to seek full performance from all customers. In selected cases, we may elect to reach agreement with customers on monetary settlements and/or contract extensions for 2013 and beyond in exchange for relief on 2012 volumes.

Macarthur is expected to contribute less than $100 million of EBITDA in 2012 given the significant cost increases necessary to correct overburden deficiencies at the Coppabella Mine and to complete major repairs at both the Coppabella and Moorvale mines that had been deferred under previous management. We expect that these expenditures will allow us to enter 2013 with a solid foundation for higher productivity, lower costs, and improved financial performance. In addition, we expect to incur increased depreciation, depletion and amortization expense in 2012 and beyond driven by a higher average depletion rate associated with the acquisition of Macarthur. As discussed in “Liquidity and Capital Resources” our debt service cost will also increase as a result of the debt incurred to fund the acquisition of Macarthur.

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We continue to manage costs and operating performance in an effort to mitigate external cost pressures, geologic issues 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.
Dodd-Frank Act. On July 21, 2010, the Dodd-Frank Act was enacted, 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 generally became 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, 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.
European Union Derivatives Regulation. In October 2011, the European Commission adopted proposals to revise its directive on markets in financial instruments (MiFID) and to enact a new regulation on markets in financial instruments (MiFIR). These proposals, which are currently under negotiation by the European Commission, European Council and European Parliament, will likely impose additional regulation of financial derivatives transactions that may apply to our hedging and our Trading and Brokerage activities. While the ultimate impact of these proposals will not be known for some time, we do expect that they will increase compliance and transaction costs associated with our hedging and our 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 super profit 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. A committee charged with consulting with industry and preparing recommendations as to the final form of the MRRT submitted its report in late December 2010. That committee's recommendations largely endorsed the mining industry's understanding as to what was agreed with the federal government prior to the federal election. In March 2011, those recommendations were accepted by the federal government, which included the recommendation that all state royalties (current and future) are creditable against MRRT payments. An implementation group was formed, which included industry participants, to assist with drafting the legislation. Draft legislation and an accompanying explanatory memorandum was released for public consultation on June 7, 2011. The final exposure draft was released for further consultation on September 16, 2011 with legislation formally submitted to the House of Representatives in November 2011. The legislation was referred to the Senate Economics Legislation Committee on November 21, 2011 with the committee due to report back to the Senate on March 14, 2012. If the MRRT becomes law, the MRRT will apply to mining profits attributable to the value of resources earned after July 1, 2012 and may affect the level of taxation incurred by our Australian operations going forward.

Carbon Pricing Framework. In the fourth quarter of 2011, the Australian government passed a legislative package that included a carbon pricing framework that commences July 1, 2012. The carbon price will initially be $23.00 Australian dollars per tonne of carbon dioxide equivalent emissions, escalated by 2.5% per year for inflation over a three year period. After June 30, 2015, the carbon price mechanism will transition to an emissions trading scheme. We believe that all of our Australian operations will be impacted by the fugitive emissions portion of the framework (defined as the methane and carbon dioxide which escapes into the atmosphere when coal is mined and gas is produced), which we estimate will initially average $2.00 to $3.25 Australian dollars per tonne of coal produced annually. Actual results will be dependent upon the volume of tons produced at each of our mining locations as the impact per tonne at our surface mines will generally be less than the impact per tonne at our underground mines. In addition, our Australian mines will be impacted by the phased reduction of the government's diesel fuel rebate to capture emissions from fuel combustion. Our North Goonyella, Wambo and Metropolitan mines will be eligible to apply for a portion of the government's approximately $1.3 billion Australian dollars of transition benefits that would provide assistance based on historical emissions intensity data to the most emissions-intensive coal mines over a six-year period.

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Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the U.S. EPA finalized CSAPR, which requires 28 states from Texas eastward (not including the New England states or Delaware) to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. The CSAPR is one of a number of significant regulations that the EPA has issued or expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. Under the CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions would commence in 2012 with further reductions effective in 2014. In October 2011, the EPA proposed amendments to the CSAPR to increase emission budgets in ten states, including Texas, and ease limits on market-based compliance options. While CSAPR had an initial compliance deadline of January 1, 2012, the rule was challenged and on December 30, 2011, the U.S. Court of Appeals for the District of Columbia stayed CSAPR and advised that the EPA is expected to continue administering CAIR until the pending challenges are resolved. Expedited briefing on the merits of the challenge is underway. We continue to evaluate the possible scenarios associated with the CSAPR and the impacts it may have on our business and our results of operations, financial condition or cash flows.

Long-Term Outlook

Our long-term global outlook remains positive. According to the BP Statistical Review of World Energy 2011, 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 2011, current policies scenario, that world primary energy demand will grow 51% between 2009 and 2035. Demand for coal is projected to rise 65%, and the growth in global electricity generation from coal is expected to be greater than the growth in oil, natural gas, nuclear, hydro, biomass, geothermal and solar combined. China and India account for more than 75% of the 2009 - 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 47% in 2009. By 2035, the IEA estimates coal's fuel share of power generation to be 49% as it continues to have the largest share of worldwide electric power production.

According to industry reports, approximately 370 gigawatts of coal-fueled electricity generating plants are currently planned or under construction around the world with expected completion between 2012 and 2016. Based on those estimates, when complete, those plants would require an estimated 1.2 billion tonnes of coal annually. In the U.S., while coal-based plant retirements are expected, the EIA is projecting coal demand to remain relatively constant through 2015.

The IEA projects that global natural gas-fueled electricity generation will have a compound annual growth rate of 2.7%, from 4.3 trillion kilowatt hours in 2009 to 8.7 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 2009. Nuclear power is expected to grow 50%, however its share of total generation is expected to fall from 13.5% to 10% between 2009 and 2035. The recent events in Japan and Germany may impact these projections. Generation from liquid fuels is projected to decline an average of 2.1% annually to 1.5% of the 2035 generation mix.

We believe that Btu Conversion applications such as coal-to-gas (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. Clean coal technology development in the U.S. has funding earmarked under the American Recovery and Reinvestment Act of 2009. In addition, the Interagency Task Force on Carbon Capture and Storage was formed to develop a comprehensive and coordinated federal strategy surrounding the commercial development of commercial carbon capture and storage projects. 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 long-term plans also include advancing projects 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 partnerships to utilize our mining experience for joint mine development. In July 2011, we entered into a framework agreement to pursue development of a 50 million-ton-per-year surface mine in Xinjiang, China. Also in July 2011, we were selected to be part of a consortium to develop the Tavan Tolgoi coking coal reserve in the South Gobi region of Mongolia. The Government of Mongolia continues to evaluate the structure and components of the mine development, and we are negotiating with other parties and the Government of Mongolia regarding long-term agreements related to the project. Any agreements would then be submitted for consideration and approval by government agencies and the Parliament of Mongolia.

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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, the state of commercial development and deployment of CCS technologies and the alternative markets for coal. 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 are the sales of our coal production to customers and from the cash generated from our trading and brokerage activities. To a lesser extent, we also generate cash from the sale of non-strategic coal reserves and surface land and from financing transactions. Along with cash and cash equivalents, our liquidity includes the available balances from our Revolver under our Credit Facility, an accounts receivable securitization program and a bank overdraft facility in Australia. Our available liquidity as of December 31, 2011 was $2.3 billion, which included cash and cash equivalents of $0.8 billion, $1.5 billion available for borrowing under the Revolver, net of outstanding letters of credit of $21.0 million, and available capacity under our accounts receivable securitization program of $41.7 million, net of outstanding letters of credit and amounts drawn. Our liquidity is also impacted by activity under certain bilateral cash collateralization arrangements.

We assumed Macarthur's three year $330.0 million Australian dollar Corporate Funding Facility (Macarthur Corporate Funding Facility) as part of the acquisition that has a maturity date of November 30, 2013. As of December 31, 2011, we had no borrowings under the Macarthur Corporate Funding Facility. The Macarthur Corporate Funding Facility has a $130.0 million Australian dollar sub-limit for bank guarantees, leaving an available capacity of $200.0 million Australian dollars at December 31, 2011. Letters of credit and cash-backed bank guarantees totaling $65.0 million Australian dollars were outstanding as of December 31, 2011. We plan to terminate the Macarthur Corporate Funding Facility in 2012.

As of December 31, 2011, approximately $284 million of our cash was held in the U.S. with approximately $515 million held by foreign subsidiaries, primarily those in our Australia Mining segment. Nearly all of the cash held by our foreign subsidiaries is denominated in U.S. dollars and is subject to additional U.S. income taxes if repatriated. The cash held in Australia is currently expected to be used to fund, in part, our organic growth projects, sustaining capital expenditures and existing operations.

We currently expect that our available liquidity and cash flow from operations will be sufficient to meet our anticipated capital requirements during the next 12 months and for the foreseeable future. In addition to the above, alternative sources of liquidity include our ability to offer and sell securities under our shelf registration statement on file with the SEC.

Capital Requirements

Our primary uses of cash include the 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. When in compliance with the financial covenants and customary default provisions of our Credit Facility and 2011 Term Loan Facility, we are not restricted in our ability to pay dividends or repurchase capital stock provided that we may only redeem and repurchase capital stock with the proceeds received from the concurrent issue of capital stock or indebtedness permitted under the Credit Facility and 2011 Term Loan Facility.

Capital Expenditures. Capital expenditures for 2012 are anticipated to be $1.2 to $1.4 billion. Approximately $800 to $950 million is earmarked for growth projects that encompass future mine development, as well as the expansion and extension of existing mines, with much of the remaining allocated to sustaining capital expenditures for existing operations. The increase in planned capital expenditures for 2012 compared to 2011 is due to the continued advancement of multiple organic growth projects at our Millennium, Metropolitan and Burton mines. Approximately 75% of the growth and expansion capital is targeted for various Australian projects for metallurgical and thermal coal, with the remainder in the U.S. Our 2012 capital expenditures will include spending to begin converting two of our Australian mines from contract mining to owner operations.

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Federal Coal Lease Expenditures. We currently anticipate that our federal coal lease expenditures will be $42.1 million in 2012 and for each of the next three years. These expenditures may increase in 2012 and beyond depending upon our participation in and the successful bidding on future federal coal leases.

Dividends. We have declared and paid quarterly dividends since our initial public offering in 2001. In January 2012, our Board of Directors approved a dividend of $0.085 per share of common stock, payable on March 1, 2012. 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 2011, we made contributions of $46.7 million. In 2012, our anticipated pension contributions needed to be at or above the Pension Protection Act thresholds is approximately $5 million.

Share Repurchase Program. At December 31, 2011, 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 2011, 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.

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.

Debt Service Costs. With the acquisition of Macarthur in 2011, our debt service costs increased with the addition of $4.1 billion of new debt that included the following.

- A 2011 Term Loan Facility of $1.0 billion with an interest rate payable of LIBOR plus 2.0%, or 2.26% (as of December 31, 2011) and a maturity date of October 28, 2016;
- 6.00% Senior Notes of $1.6 billion due November 2018 (the 6.00% Senior Notes), with interest payable on May15 and November 15 of each year, commencing May15, 2012; and
- 6.25% Senior Notes of $1.5 billion due November 2021 (the 6.25% Senior Notes), with interest payable on May15 and November 15 of each year, commencing May15, 2012.

While these new debt instruments increased the annual amount of interest to be paid for 2012 and beyond, only the 2011 Term Loan Facility resulted in a $50.0 million increase to our annual amount of principal to be paid ($37.5 million in 2012). See the Contractual Obligations section for our estimated debt service costs as of December 31, 2011 for the next five years and thereafter. See Note 11 to our consolidated financial statements for additional information on all of our outstanding debt.

On November 15, 2011, we, the Guarantors and the initial purchasers of the 6.00% Senior Notes and the 6.25% Senior Notes entered into a registration rights agreement (the Registration Rights Agreement). Subject to the terms of the Registration Rights Agreement, we will use our reasonable best efforts to register with the SEC exchange notes having substantially identical terms as the 6.00% Senior Notes and the 6.25% Senior Notes and to exchange freely tradable exchange notes for such notes within 365 days after the issue date of the 6.00% Senior Notes and the 6.25% Senior Notes (effectiveness target date). If we fail to meet the effectiveness target date (a registration default), the annual interest rate on the 6.00% Senior Notes and the 6.25% Senior Notes will increase by 0.25% for each 90-day period during which the default continues, up to a maximum additional interest rate of 1.0% until the registration default is cured.

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Our total indebtedness as of December 31, 2011 and 2010, consisted of the following:

	December 31, 2011	December 31, 2010
	(Dollars in millions)	
Term Loan	$468.8	$493.8
2011 Term Loan Facility	1,000.0	—
5.875% Senior Notes due April 2016	—	218.1
7.375% Senior Notes due November 2016	650.0	650.0
6.00% Senior Notes due November 2018	1,600.0	—
6.50% Senior Notes due September 2020	650.0	650.0
6.25% Senior Notes due November 2021	1,500.0	—
7.875% Senior Notes due November 2026	247.3	247.2
Convertible Junior Subordinated Debentures due 2066	375.2	373.3
Capital lease obligations	122.8	69.6
Fair value hedge adjustment	—	2.2
Other	43.4	45.8
Total	$6,657.5	$2,750.0

We were in compliance with all of the covenants of the Credit Facility, the 2011 Term Loan Facility, the 7.375% Senior Notes, the 6.00% Senior Notes, the 6.50% Senior Notes, the 6.25% Senior Notes, the 7.875% Senior Notes and the Debentures as of December 31, 2011. As market conditions warrant, we may from time to time repurchase debt securities issued by us, in private negotiated or open market transactions, by tender offer or otherwise.

Margin. As part of our trading and brokerage activities, we may be required to post margin with an exchange or one of our counterparties. The amount and timing of margin posted can vary with the volume of trades and market price volatility. Total margin held at December 31, 2011 was $18.1 million as compared to total margin posted of $192.1 million at December 31, 2010. For the year ended December 31, 2011, net cash inflows for margin were $210.2 million. Net cash outflows for margin were $161.2 million for the year ended December 31, 2010.

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.

Historical Cash Flows

	Year Ended December 31, 2011	Year Ended December 31, 2010	Increase (Decrease) to Cash Flow $	Increase (Decrease) to Cash Flow %
	(Dollars in millions)			
Net cash provided by operating activities	$1,633.2	$1,087.1	$546.1	50.2 %
Net cash used in investing activities	(3,807.8)	(703.6)	(3,104.2)	441.2 %
Net cash provided by (used in) financing activities	1,678.5	(77.1)	1,755.6	(2,277.0)%

Operating Activities. The changes from the prior year were due to the following:

- Higher cash inflows associated with a return of margin posted on trading activities;
- Increased operating cash flows generated from our Australian Mining operations driven by higher pricing; and
- A prior year decrease in the utilization of our accounts receivable securitization program.

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Investing Activities. The changes from the prior year were due to the following:

- $2.8 billion for the acquisition of a controlling interest in Macarthur; and
- Higher current year capital spending, including Prairie State, of $259.2 million related primarily to our expansion projects in Australia, partially offset by prior year spending to establish and ramp up operations at our Bear Run Mine.

Financing Activities. The changes from the prior year were due to the following:

- A net increase in borrowings of long-term debt compared to 2010 of $3.9 billion driven by the $4.1 billion of debt proceeds that were used, in part, to fund the Macarthur acquisition; and
- Acquisition of noncontrolling interests of $2.0 billion.

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2011:

	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)	$10,704.2	$458.8	$961.1	$2,722.8	$6,561.5
Capital lease obligations (principal and interest)	142.0	32.3	67.2	20.8	21.7
Operating lease obligations	610.9	123.1	196.8	139.9	151.1
Unconditional purchase obligations(1)	1,313.0	743.6	569.4	—	—
Coal reserve lease and royalty obligations	227.8	50.7	98.8	50.4	27.9
Take or pay obligations(2)	4,547.6	443.1	824.4	469.0	2,811.1
Other long-term liabilities(3)	3,035.6	174.1	331.0	324.0	2,206.5
Total contractual cash obligations	$20,581.1	$2,025.7	$3,048.7	$3,726.9	$11,779.8

(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. Also includes commitments under electricity, water and coal washing agreements with joint ventures.

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

We do not expect any of the $119.6 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.

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Accounts Receivable Securitization. We have an accounts receivable securitization program (securitization program) with a maximum capacity of $275.0 million through our wholly-owned, bankruptcy-remote subsidiary (Seller). At December 31, 2011, we had $41.7 million available under the securitization program, net of outstanding letters of credit and amounts drawn. Under the securitization program, 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 the Revolver portion of our Credit Facility, effectively managing our overall borrowing costs and providing an additional source for working capital. 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, 2011, we received total consideration of $4,633.4 million related to accounts receivable sold under the securitization program, including $3,462.7 million of cash up front from the sale of the receivables, an additional $1,004.8 million of cash upon the collection of the underlying receivables, and $165.9 million that had not been collected at December 31, 2011 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, 2011 and 2010.

The securitization activity has been reflected in the consolidated statements of cash flows as an 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 $2.0 million, $2.4 million and $4.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Other Off-Balance Sheet Arrangements. From time to time, we enter into coal offtake agreements with counterparties where, as a part of the arrangements, we may provide certain financial guarantees on behalf of the counterparties. As of December 31, 2011, we had in place guarantees of $10.0 million on behalf of our counterparties relating to such agreements. To mitigate risk, we place liens on the counterparties' production equipment or require performance bonds.

In January 2011, we entered into a bilateral cash collateralization agreement in support of certain letters of credit whereby we posted cash collateral in lieu of utilizing our Credit Facility. The capacity under this new agreement is $37.0 million, all of which was posted as collateral at December 31, 2011. As of December 31, 2011, we had a total of $79.7 million posted as collateral under such agreements. The cash collateral is classified within "Cash and cash equivalents" given our ability to substitute letters of credit at any time for this cash collateral.

As discussed above in Capital Resources, we also had $65.0 million (Australian dollars) of letters of credit and cash backed bank guarantees outstanding under the Macarthur Corporate Funding Facility at December 31, 2011.

See Note 22 to our consolidated financial statements for a discussion of our guarantees.

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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 14 and 15 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, 2011 for pension and postretirement liabilities totaled \$119.7 million, while funding payments were \$112.8 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:	For Year Ended December 31, 2011	
	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components[1]	\$8.2	\$(6.9)
Effect on total postretirement benefit obligation[1]	\$121.8	\$(104.6)

Discount rate:	For Year Ended December 31, 2011	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components[1]	\$0.7	\$(0.7)
Effect on total postretirement benefit obligation[1]	\$(56.8)	\$64.8

(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 11.70 years at January 1, 2012.

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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, 2011 was $53.1 million, and payments totaled $16.9 million. See Note 13 to our consolidated financial statements for additional details regarding our asset retirement obligations.

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

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

Business Combinations. We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets, and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates, and asset lives, among other items.

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.

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At December 31, 2011 and 2010, 1% ($8.7 million) and 3% ($18.6 million), respectively, of our net financial assets were categorized as Level 3. See Notes 6 and 7 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, which includes bilaterally-settled and exchange-settled over-the-counter trading as well as brokered trading of coal, is evaluated using a value at risk (VaR) analysis. VaR analysis is not used to evaluate our non-trading interest rate, diesel fuel, explosives and currency hedging portfolios or coal trading activities we employ in support of coal production (as discussed 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

Coal Price Risk Monitored Using VaR. We engage in direct and brokered trading of coal, ocean freight and fuel-related commodities in over-the-counter markets. 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 risk, as measured by VaR, that we may assume at any point in time on trading and brokerage activities.

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 condensed consolidated financial statements. Our trading portfolio included forwards, swaps and options as of December 31, 2011.

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 expected loss in portfolio value 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 calculates a 5 to 15-day holding period dependent upon the products within our portfolio at the time of VaR measurement 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 estimate the maximum loss expected in the 5% of the time the portfolio value exceeds measured VaR.

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

During the year ended December 31, 2011, the actual low, high, and average VaR was $3.5 million, $30.6 million and $13.4 million, respectively.

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Other Risk Exposures. We also use our coal trading and brokerage platform to support various coal production-related activities. These transactions may involve coal to be produced from our mines, coal sourcing arrangements with third-party mining companies, joint venture positions with producers or offtake agreements with producers. While the support activities (e.g. forward sale of coal to be produced and/or purchased) may ultimately involve market risk sensitive instruments, the sourcing of coal in these arrangements does not involve market risk sensitive instruments and does not encompass the commodity price risks that we monitor through VaR, as discussed above.

Future Realization. As of December 31, 2011, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio Total
2012	65%
2013	29%
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 6 to our consolidated financial statements. Assuming we had no hedges in place, our exposure in operating costs and expenses due to a $0.05 change in the Australian dollar/U.S. dollar exchange rate is approximately $150 million for 2012. However, taking into consideration hedges currently in place, our net exposure to the same rate change is approximately $65 million for 2012. The table at the end of Item 7A shows the notional amount of our hedge contracts as of December 31, 2011.

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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 6 to our consolidated financial statements. As of December 31, 2011, we had $5.2 billion of fixed-rate borrowings and $1.5 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 $15 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 $338 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%, 91% and 93% of our worldwide sales (by volume) for the years ended December 31, 2011, 2010 and 2009, respectively. Substantially all of our coal in the U.S. is contracted in 2012 at planned production levels. We had 40% to 50% of seaborne thermal coal volumes available for pricing in at January 24, 2012. We expect near-term macroeconomic movements to dictate quarterly metallurgical coal pricing for the remainder of the 2012 and we are targeting total 2012 metallurgical coal sales of approximately 14 to 15 million tons.

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 160 to 165 million gallons of diesel fuel in 2012. 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 $38 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 $15 million.

Notional amounts outstanding under explosives-related swap contracts are noted in the table at the end of Item 7A. We expect to consume 380,000 to 390,000 tons of explosives during 2012 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 $7 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.

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Notional Amounts and Fair Value. The following summarizes our interest rate, foreign currency and commodity positions at December 31, 2011:

	Notional Amount by Year of Maturity						
	Total	2012	2013	2014	2015	2016	2017 and thereafter
Foreign Currency							
A$:US$ hedge contracts (A$ millions)	$3,910.6	$1,750.5	$1,309.6	$850.5	$—	$—	$—
GBP:US$ hedge contracts (GBP millions)	6.5	6.5	—	—	—	—	—
Commodity Contracts							
Diesel fuel hedge contracts (million gallons)	189.6	86.0	68.0	35.6	—	—	—
U.S. explosives hedge contracts (million MMBtu)	7.7	3.9	2.6	1.2	—	—	—

	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)	$3,910.6	$—	$—	$491.3
GBP:US$ hedge contracts (GBP millions)	6.5	—	—	$(0.7)
Commodity Contracts				
Diesel fuel hedge contracts (million gallons)	189.6	—	—	$43.7
U.S. explosives hedge contracts (million MMBtu)	7.7	—	—	$(10.7)

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, 2011, 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, 2011, and concluded that such controls and procedures are effective to provide reasonable assurance that the desired control objectives were achieved.

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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.

On October 26, 2011, we acquired Macarthur. As a result of the acquisition, we are in the process of reviewing the internal control structure of Macarthur and, if necessary, will make appropriate changes as we incorporate our controls and procedures into the acquired business. Except for the acquisition, there have been no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2011 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 are 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, 2011.

Management's assessment of the effectiveness of our internal control over financial reporting did not include the internal controls of Macarthur, which was acquired on October 26, 2011. In accordance with SEC guidance regarding the reporting of internal control over financial reporting in connection with an acquisition, management may omit an assessment of an acquired business' internal control over financial reporting from management's assessment of internal control over financial reporting for a period not to exceed one year from the date of acquisition. Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2012 will include the internal controls of Macarthur. Macarthur is included in our consolidated financial statements and constituted $5.3 billion of total assets, $152.9 million of revenues and contributed a net loss of $47.9 million of our net income as of and for the year ended December 31, 2011.

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

Gregory H. Boyce
Chairman and Chief Executive Officer

/s/ Michael C. Crews
Michael C. Crews
Executive Vice President and
Chief Financial Officer

February 27, 2012

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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, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company’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.

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of entities acquired through the Macarthur Coal Limited acquisition, which is included in the 2011 consolidated financial statements of the Company and constituted $5.3 billion and $5.0 billion of total and net assets, respectively, as of December 31, 2011, and $152.9 million and $47.9 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of entities acquired through the Macarthur Coal Limited acquisition.

In our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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, 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 27, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
St. Louis, Missouri
February 27, 2012

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Item 9B. Other Information.
None.
PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by Item 401 of Regulation S-K is included under the caption “Election of Directors-Director Qualifications” in our 2012 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 2012 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 2012 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 2012 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, 2011:

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	1,703,574 (1)	$32.53 (2)	16,929,167 (3)
Equity compensation plans not approved by security holders	—	—	—
Total	1,703,574	$32.53	16,929,167

(1) Includes 57,528 shares issuable pursuant to outstanding deferred stock units and 344,439 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 2,142,300 shares available for issuance under our U.S. Employee Stock Purchase Plan and 962,604 shares available for issuance under our Australian Employee Stock Purchase Plan.

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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 2012 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 2012 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. Exhibit, Financial Statement Schedules.

(a) Documents Filed as Part of the Report

(1) Financial Statements.

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

(2) Financial Statement Schedule.

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

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

(3) Exhibits.

See Exhibit Index hereto.

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

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SIGNATURES

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

PEABODY ENERGY CORPORATION

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

Date: February 27, 2012

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 27, 2012
/s/ MICHAEL C. CREWS Michael C. Crews	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2012
/s/ WILLIAM A. COLEY William A. Coley	Director	February 27, 2012
/s/ WILLIAM E. JAMES William E. James	Director	February 27, 2012
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 27, 2012
/s/ M. FRANCES KEETH M. Frances Keeth	Director	February 27, 2012
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 27, 2012
/s/ ROBERT A. MALONE Robert A. Malone	Director	February 27, 2012
/s/ WILLIAM C. RUSNACK William C. Rusnack	Director	February 27, 2012
/s/ JOHN F. TURNER John F. Turner	Director	February 27, 2012
/s/ SANDRA VAN TREASE Sandra Van Trease	Director	February 27, 2012
/s/ ALAN H. WASHKOWITZ	Director	February 27, 2012

Alan H. Washkowitz

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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, 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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 27, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
St. Louis, Missouri
February 27, 2012

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2011	2010	2009
	(Dollars in millions, except per share data)		
Revenues			
Sales	$7,091.3	$6,211.2	$5,303.1
Other revenues	883.1	528.7	543.9
Total revenues	7,974.4	6,739.9	5,847.0
Costs and expenses			
Operating costs and expenses	5,550.0	4,697.3	