PEABODY ENERGY CORP
Form 10-K
February 25, 2013

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, 2012
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

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. (X)

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, 2012: Common Stock, par value $0.01 per share, $6.6 billion.

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of February 15, 2013: Common Stock, par value $0.01 per share, 269,630,757 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 2013 Annual Meeting of Shareholders (the Company's 2013 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.

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 supply and 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;
- global steel demand and the downstream impact on metallurgical coal prices;
- 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;
- impact of take-or-pay arrangements for rail and port commitments for the delivery of coal;
- 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, but not limited to, new environmental and mine safety requirements and changes in income tax regulations, sales-related royalties or other regulatory taxes;
- litigation, including claims not yet asserted;
- terrorist attacks or security threats;
- impacts of pandemic illnesses; and
- other factors, including those discussed in "Legal Proceedings," set forth in Part I, Item 3 of this report and "Risk Factors," set forth in Part I, 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.
When used in this filing, the term "ton" refers to short or net tons, equal to 2,000 pounds (907.18 kilograms), while "tonne" refers to metric tons, equal to 2,294.62 pounds (1,000 kilograms).

PART I

Item 1. Business.

Overview

Peabody Energy Corporation is the world’s largest private-sector coal company. We own interests in 28 active coal mining operations located in the United States (U.S.) and Australia. We have a majority interest in 27 of those coal operations and a 50% equity interest in the Middlemount Mine in Australia. We also own a noncontrolling interest in a mining operation in Venezuela. In addition to our mining operations, we market and broker coal from our operations and other coal producers, both as principal and agent, and trade coal and freight-related contracts through trading and business offices in China, Australia, the United Kingdom, Germany, Singapore, Indonesia, India and the U.S.

History and Development

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 U.S. and international coal markets with the highest demand. Acquisitions and divestitures of note include the following.

- In 2004, we acquired coal operations from RAG Coal International AC, expanding our presence in both Australia and Colorado.
- In 2006, we further expanded our presence in Australia with the acquisition of Excel Coal Limited.
- In 2007, we spun off Patriot Coal Corporation (Patriot), which included mines in West Virginia and Kentucky and coal reserves in the Illinois Basin and Appalachia, through a dividend of all outstanding Patriot shares.
- In 2011, we acquired Macarthur Coal Limited (PEA-PCI), an independent coal company in Australia, which included two operating mines, a 50% equity-affiliate joint venture arrangement and several development projects.

Our core strategies to achieve long-term growth and generate positive returns on investment are:

1) Execute the basics of best-in-class safety, operational efficiency and marketing;
2) Capitalize on organic growth and development opportunities as warranted by global coal market conditions; and
3) Expand our presence in high-growth global markets.

In 2012, we advanced multiple growth and development projects in Australia and, to a lesser extent, the U.S., that involved the expansion and extension of existing mines and the development of future mines. We also initiated projects to convert our Wilpinjong and Millennium mines in Australia from contract mining to owner-operated sites and completed the integration of PEA-PCI operations into our Australian platform.

In response to near-term challenges in global coal markets, we plan to limit our 2013 capital spending to predominantly maintenance capital necessary to preserve the productive capacity of our existing mines and the selective advancement of certain late-stage growth and development projects in Australia. Those projects we plan to advance include the completion of the conversion of our Wilpinjong and Millennium mines to owner-operated sites, the initiation of the conversion of our Wambo Open-Cut Mine to an owner-operated site and equipment and facility upgrades at our Metropolitan and North Goonyella longwall mining operations in Australia.

We will continue to explore opportunities to extend our presence in the Asia-Pacific region, such as through joint mine development partnerships with other companies and governments to leverage our experience in managing safe and reliable coal mining operations.

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Segment and Geographic Information

We conduct business through four principal segments: Western U.S. Mining, Midwestern U.S. Mining, Australian Mining and Trading and Brokerage. Our fifth segment, Corporate and Other, includes mining and export/transportation joint ventures, activities associated with certain energy-related commercial matters, Btu Conversion, the optimization of our coal reserve and real estate holdings and costs associated with past mining obligations.

Segment and geographic financial information is contained in Note 26. "Segment and Geographic Information" to our consolidated financial statements and is incorporated herein by reference.

Mining Segments

The maps that follow display our active mine locations as of December 31, 2012, excluding mines held for sale. Also shown are the primary ports we use in the U.S. and in Australia for coal exports and our corporate headquarters in St. Louis, Missouri.

U.S. Mining Operations

The principal business of our Western and Midwestern U.S. Mining segments is the mining, preparation and sales of thermal coal, which is typically supplied to U.S. electricity generators and industrial customers for power generation, with a portion sold into seaborne export markets. Our Western U.S. Mining segment is comprised of our Powder River Basin, Southwest and Colorado mining operations. The mines in that segment are generally characterized by surface mining extraction processes and coal with a low sulfur and Btu content. Our Midwestern U.S. Mining segment includes our active mining operations in Illinois and Indiana, which are characterized by a mix of surface and underground mining extraction processes and coal with a high sulfur and Btu content. Customer transportation costs associated with our Western U.S. Mining coal products are generally higher than those of our Midwestern U.S. Mining segment due to comparatively longer shipping distances.

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Australian Mining Operations

Our Australian Mining segment 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 for the mining of various qualities of metallurgical and thermal coal. Metallurgical coal qualities produced by that segment 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 partial replacement for coke made from coking coal. The acquisition of PEA-PCI in the fourth quarter of 2011 increased our proven and probable reserves of low volatile PCI (LV PCI) coal, coking coal and thermal coal. Our Australian Mining segment 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. Revenues from individual countries generally vary year by year based on demand for electricity and steel, global economic conditions and several other factors, including weather, governmental policies, economic conditions and other items, specific to each country.

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The table below summarizes information regarding the operating characteristics of each of our active mines (excluding mines classified as discontinued operations) in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2012.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Transport Method	2012 Tons Sold (In millions)
Western U.S. Mining						
North Antelope Rochelle	Wright, WY	S	DL, T/S	T	R	107.7
Caballo	Gillette, WY	S	D, T/S	T	R	16.8
Rawhide	Gillette, WY	S	D, T/S	T	R	14.7
El Segundo	Grants, NM	S	T/S	T	R	8.4
Twentymile	Oak Creek, CO	U	LW	T	R, T	8.3
Kayenta	Kayenta, AZ	S	DL, T/S	T	R	7.5
Lee Ranch	Grants, NM	S	DL, T/S	T	R	0.8
Other (1)	—	—	—	—	—	1.0
Midwestern U.S. Mining						
Bear Run	Carlisle, IN	S	DL, D, T/S	T	T, R	7.7
Gateway	Coulterville, IL	U	CM	T	T, R, R/B	2.8
Francisco Underground	Francisco, IN	U	CM	T	R	2.8
Somerville Central	Oakland City, IN	S	DL, D, T/S	T	R, T/R, T/B	2.5
Cottage Grove	Equality, IL	S	D, T/S	T	T/B	2.1
Wild Boar	Lynnville, IN	S	D, T/S	T	T, R, R/B	2.0
Somerville South (2)	Oakland City, IN	S	D, T/S	T	R, T/R, T/B	1.5
Wildcat Hills Underground	Eldorado, IL	U	CM	T	T/B	1.5
Viking — Corning Pit	Cannelburg, IN	S	D, T/S	T	T, T/R	1.3
Somerville North (2)	Oakland City, IN	S	D, T/S	T	R, T/R, T/B	1.1
Other (3)	—	—	—	—	—	2.1
Australian Mining						
Wilpinjong *	Wilpinjong, New South Wales	S	D, T/S	T	R, EV	12.5
North Wambo Underground (2)	Warkworth, New South Wales	U	LW	T/P	R, EV	3.5
Wambo Open-Cut * (2)	Warkworth, New South Wales	S	T/S	T	R, EV	3.0
Millennium *	Moranbah, Queensland	S	T/S	M/P	R, EV	3.0
North Goonyella	Glenden, Queensland	U	LW	M	R, EV	2.6
Coppabella (4)	Moranbah, Queensland	S	DL, D, T/S	P	R, EV	2.6
Metropolitan	Helensburgh, New South Wales	U	LW	M	R, EV	2.1
Moorvale * (4)	Moranbah, Queensland	S	T/S	M/P	R, EV	1.9
Burton *	Glenden, Queensland	S	T/S	T/M	R, EV	0.9
Eaglefield *	Glenden, Queensland	S	T/S	M	R, EV	0.9
Middlemount (5)	Middlemount, Queensland	S	T/S	T/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) “Other” in Western U.S. Mining primarily consists of purchased coal used to satisfy certain coal supply agreements.

(2) Represents mines in which we have non-controlling ownership interests.

(3) Represented 2012 tons sold from our Willow Lake Mine, which commenced closure activities in November 2012. Refer to Note 3. "Asset Impairment and Mine Closure Costs" to our consolidated financial statements for additional details.

(4) We own a 73.3% undivided interest in an unincorporated joint venture that owns the Coppabella and Moorvale mines.

(5) We own a 50.0% equity interest in Middlemount Coal Pty Ltd., which owns the Middlemount Mine. Because that entity is accounted for as an unconsolidated equity affiliate, 2012 tons sold from that mine have been excluded from the table above.

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We also own a 48.37% noncontrolling interest in Carbones del Guasare S.A., which operates the Paso Diablo Mine, a surface operation in northwestern Venezuela that produces thermal coal.

Refer to the "Summary of Coal Production and Sulfur Content of Assigned Reserves" table within Part I, Item 2. "Properties," which is incorporated by reference herein, for additional information regarding coal reserves, product characteristics and production volume associated with each mine.

Trading and Brokerage Segment

Our Trading and Brokerage segment engages in the direct and brokered trading of coal and freight-related contracts through trading and business offices in Australia, China, Germany, India, Indonesia, Singapore, the United Kingdom and the U.S. (listed alphabetically). Coal brokering is conducted both as principal and agent in support of various coal production-related activities that may involve coal produced from our mines, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. Our Trading and Brokerage segment also provides transportation-related services in support of our coal trading strategy, as well as hedging activities in support of sales from 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 9.3 billion tons of proven and probable coal reserves and approximately 500,000 acres of surface property. We have an ongoing asset optimization program whereby our resource development group regularly reviews these reserves and surface properties for opportunities to generate earnings and cash flow through the sale or exchange of non-strategic coal reserves and surface lands. In addition, we generate revenue through royalties from coal reserves and oil and gas rights leased to third parties and farm income from surface lands under third-party contracts.

Middlemount Mine. We own a 50% equity interest in the Middlemount Mine in Queensland, Australia. The mine predominantly produces semi-hard coking coal and PCI coal, with a small portion of thermal coal, for sale into seaborne coal markets through rail and port capacity contracted through Abbot Point Coal Terminal, with future capacity also secured at Dalrymple Bay Coal Terminal. Mining operations commenced at Middlemount Mine in late 2011 and that mine continued to ramp up production and invest in operational improvements through 2012, during which time it also produced and sold approximately 2 million tons of coal (on a 100% basis).

Paso Diablo Mine. We own a 48.37% noncontrolling 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. According to the related operating agreement, 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. We fully impaired the carrying value of our investment in 2009.

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 in which we also own an equity interest. The joint venture holds several exploration licenses and continues to evaluate potential metallurgical and thermal coal projects for possible development.

Export Facilities. We have a 37.5% 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 plant and adjacent coal mine in Washington, St. Clair and Randolph counties in Illinois, which commenced commercial operations during 2012. We are responsible for our 5.06% share of Prairie State's production costs and marketing and selling our share of electricity generated by the facility.

Btu Conversion. Btu Conversion involves projects designed to expand the uses of coal such as through conversion to transportation fuels and coal gasification technologies. We are pursuing a project with the government of Inner Mongolia and other Chinese partners to explore development opportunities for a large surface mine and downstream coal gasification facility that would produce methanol, chemicals or fuel products.

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Clean Coal Technology. We continue to support and advance clean coal technology development and other “green coal” initiatives seeking to reduce global atmospheric levels of carbon dioxide and other emissions. In China, we are the only non-Chinese equity partner in GreenGen, a near-zero emissions coal-fueled power plant with carbon capture and storage (CCS) and research center near Tianjin, China that commenced operations in 2012, and a founding member of the U.S.-China Energy Cooperation program. In Australia, we have an ongoing commitment to the Australian COAL21 Fund, which was designed to support clean coal technology demonstration projects and research in Australia, and are also a founding member of the Global Carbon Capture and Storage Institute, an international initiative hosted by the Australian government to accelerate commercialization of CCS technologies through development of 20 integrated, industrial-scale demonstration projects. In the U.S., we are a founding member of the Consortium for Clean Coal Utilization in Missouri, the FutureGen Alliance in Illinois, the National Carbon Capture Center in Alabama and the Western Kentucky Carbon Storage Foundation.

Captive Insurance Entities. A portion of our insurance risks associated with workers’ compensation, general liability and auto liability coverage is self-insured through two wholly-owned captive insurance companies. The captive entities invoice certain of our subsidiaries for the premiums on these policies, pay the related claims, maintain reserves for anticipated losses and invest funds to pay future claims.

Coal Supply Agreements

Customers. 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), with a smaller portion sold in spot markets. Sales under those long-term coal supply agreements comprised approximately 89%, 91% and 91% of our worldwide sales (by volume) for the years ended December 31, 2012, 2011 and 2010, respectively.

For the year ended December 31, 2012, we derived 26% of our total coal sales revenues from our five largest customers. Those five customers were supplied primarily from 44 coal supply agreements (excluding trading transactions) expiring at various times from 2012 to 2026. The contract contributing the greatest amount of annual revenue in 2012 was approximately $320 million, or approximately 5% of our 2012 total coal sales revenue base and is due to expire in 2026.

Backlog. Our sales backlog, which includes coal supply agreements subject to price reopener and/or extension provisions, was approximately 900 million and 1 billion tons of coal as of January 1, 2013 and 2012, respectively. Contracts in backlog have remaining terms ranging from one to 15 years and represent nearly four years of production based on our 2012 production volume of 225.7 million tons. Approximately 78% of our backlog is expected to be filled beyond 2013.

U.S. Revenues from our Western and Midwestern U.S. Mining segments, in aggregate, represented approximately 54%, 55% and 59% of our total revenue base for the years ended December 31, 2012, 2011 and 2010, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 85%, 89% and 88% of our sales volumes from mining operations. We expect to continue selling a significant portion of our Western U.S. Mining and Midwestern U.S. Mining segment coal production under long-term supply agreements, and customers of those segments continue to pursue long-term sales agreements in recognition of the importance of reliability, service and predictable coal prices to their operations. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of those 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. Revenues from our Australian Mining segment represented approximately 43%, 39% and 36% of our total revenue base for the years ended December 31, 2012, 2011 and 2010, respectively, during which periods the coal mining activities of that segment contributed respective amounts of 15%, 11% and 12% of our sales volumes from mining operations. Production is sold primarily into the seaborne metallurgical and thermal markets through annual and multi-year international coal agreements that contain provisions requiring both parties to renegotiate pricing periodically. Industry commercial practice, and our practice, is to negotiate pricing for metallurgical and seaborne thermal coal contracts on a quarterly and annual basis, respectively.

Transportation

Methods of Distribution. 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. Exporters 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 a component of the shipping costs of our Australian exports as certain ports continue to experience vessel queues, though such conditions generally improved during 2012 compared to the prior year.

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. Refer to the table on page 5 in the foregoing "Mining Segments" section for a summary of transportation methods by mine.

Export Facilities. 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, the St. James Stevedoring Anchorages terminal in Convent, Louisiana and the Kinder Morgan terminal near Houston, Texas. Our U.S. Mining operations exported approximately 3%, 3% and 1% of its tons sold for the years ended December 31, 2012, 2011 and 2010, respectively.

In Australia, we have generally secured our ability to transport coal through rail contracts and interests in three east coast coal export terminals that are primarily funded through take-or-pay arrangements (see the "Liquidity and Capital Resources" section in Part II, Item 7. "Management's Discussion and Analysis of Financial Conditions and Results of Operations" for additional information). In Queensland, seaborne metallurgical and thermal coal from our mines is exported through the Dalrymple Bay Coal Terminal, in addition to the Abbot Point Coal Terminal used by our joint venture Middlemount Mine. 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 77%, 74% and 71% of its tons into the seaborne coal markets for the years ended December 31, 2012, 2011 and 2010.

We are currently pursuing a U.S. west coast port facility that will allow us to export our Powder River Basin coal products to Asian markets.

Suppliers

Mining Supplies and Equipment. The principal 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 products (including roof control materials), lubricants and electricity. 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.

Historically, there has been some consolidation in the supplier base providing mining materials to the coal industry for certain of these goods, such as explosives in the U.S. and both surface and underground mining equipment globally, which has limited the number of sources for these materials. In situations where we have elected to concentrate a large portion of our purchases with one supplier, it has been to take advantage of cost savings from larger volumes of purchases, benefit from long-term pricing for parts and/or ensure security of supply and/or allow for equipment fleet standardization. Supplier concentration related to our mining equipment also allows us to benefit from fleet standardization, which in turn improves asset utilization by facilitating the development of common maintenance practices across our global platform and enhancing our flexibility to move equipment between mines as necessary.

Market demand and lead times for certain OTR tires continued to increase on a year-over-year basis in 2012, with demand continuing to outpace supply. We do not expect these challenges in lead times or supply 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 OTR tire suppliers.

Surface and underground mining equipment demand and lead times decreased substantially on a year-over-year basis in 2012 due to adverse market conditions experienced across several extractive industry sectors. This is consistent with a decline in our own demand for such equipment during that period as we have sought to defer new and early stage development projects, while continuing to complete several late stage capital projects in Australia, to reduce our near-term capital requirements. We continue to use our global leverage with major suppliers to either ensure security of supply to meet the requirements of our growth and development projects or to delay deliveries when warranted by adverse market conditions.

Services. We also purchase services at our mine sites, including services related to maintenance for mining equipment, construction, temporary labor and other various contracted services, such as contract mining for both production and development and explosive services. 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 advance new technologies to maximize safety. Personnel tracking systems have been deployed across all underground operations in the U.S. that provide continuous real-time locations of workers underground.We are testing a proximity detection system at a section of one of our mines that is designed to automatically stop mining equipment if a person is detected within the operating range of a continuous miner or coal hauler. The proximity detection system has been approved by the U.S. Mine Safety and Health Administration (MSHA) and we have the ability to incorporate that technology into other operating sites prospectively once testing has been successfully completed.

We also continue to emphasize the application of technical innovation to improve equipment performance and operating efficiencies. Development is typically undertaken and funded by equipment suppliers with our engineering, maintenance and purchasing personnel providing input and expertise to those suppliers who then design and produce equipment that we believe will enhance our operating performance and capabilities.

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 trains, monitor coal quality and customer shipments and manage mine operations and pit blending to enhance our reliability and product consistency.

Competition

The markets in which we sell our coal are highly competitive. We compete directly with other coal producers and indirectly with producers of other energy products that provide an alternative to coal use. We compete on the basis of coal quality, delivered price, geographic diversity, customer service and support and reliability of supply. Our principal U.S. direct 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 38% of total U.S. coal production in 2011 according to the National Mining Association's "2011 Coal Producer Survey," the most recent data publicly available as of February 25, 2013. Major international competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Rio Tinto, Shenhua Group and Xstrata PLC.

Demand for coal and the prices that we will be able to obtain for our coal are influenced by factors beyond our control, including supply and demand for electricity and steel, the impact of weather on heating and cooling demand and taxes and environmental regulations imposed by the U.S. and foreign governments. Thermal coal demand is also influenced by the availability and relative cost of alternative fuels, with customers focused on securing the lowest cost fuel supply in order to produce electric power at a competitive price. These alternatives include natural gas, fuel oil and nuclear, hydroelectric, wind, biomass and solar power sources. Natural gas currently presents the most significant substitution threat to thermal coal in the U.S. driven by a year-over-year decline in full year average U.S. natural gas prices of 31% observed in 2012. The U.S. Energy Information Administration (EIA) reported in its February 2013 "Short-Term Energy Outlook" that coal's share of U.S. electricity generation for all sectors declined from 42% in 2011 to 37% in 2012, with a substantial portion of that lost share assumed by natural gas. We believe the economics of gas-to-coal switching enable demand for thermal coals produced in the U.S. Powder River and Illinois basins in which we produce to benefit when natural gas prices rise above ranges of $2.50 to $2.75 and $3.25 to $3.50 per mmBtu, respectively, and to decline when natural gas prices fall below those levels. The EIA expects full year average U.S. natural gas prices to increase year-over-year by 28% and 9% in 2013 and 2014, respectively, and correspondingly projects coal's share of U.S. electricity generation for all sectors to increase to 39% in those periods.

Working Capital

We generally fund our working capital requirements through a combination of existing cash and cash equivalents, the sale of our coal production to customers and our trading and brokerage activities. 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 also available to fund our working capital requirements. Refer to the "Liquidity and Capital Resources" section of Part II, Item 7. "Management's Discussion and Analysis of Financial Conditions and Results of Operations" for additional information regarding working capital.

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Employees
We had approximately 8,200 employees as of December 31, 2012, including approximately 5,700 hourly employees. Those amounts include approximately 400 employees of the Willow Lake Mine that were provided Worker Adjustment and Retraining Notification letters in November 2012 in connection with the closure of that mine and who will remain employed by us into the first quarter of 2013. Additional information on our employees and related labor relations matters is contained in Note 22. "Management - Labor Relations" to our consolidated financial statements.
Executive Officers of the Company
Set forth below are the names, ages as of February 15, 2013 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	58	Chairman and Chief Executive Officer, Director
Michael C. Crews	45	Executive Vice President and Chief Financial Officer
Sharon D. Fiehler	56	Executive Vice President and Chief Administrative Officer
Eric Ford	58	Chairman - Australia
Christopher J. Hagedorn	40	President - Asia and Trading
Jeane L. Hull	58	Executive Vice President and Chief Technical Officer
Charles F. Meintjes	50	President - Australia
Alexander C. Schoch	58	Executive Vice President Law, Chief Legal Officer and Secretary
Kemal Williamson	53	President - Americas

Gregory H. Boyce was elected Chairman of the Board in October 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. He 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. Mr. Boyce serves on the board of directors of Marathon Oil Corporation. He is Deputy Chairman of the Coal Industry Advisory Board of the International Energy Agency and is a former Chairman of the National Mining Association. He is a member of the National Coal Council; The Business Council; Business Roundtable; the Board of Trustees of Washington University in St. Louis; the Board of Commissioners for the St. Louis Science Center and the Advisory Council of the University of Arizona's Department of Mining and Geological Engineering.Mr. Boyce is also President of the Board of Directors of Variety - The Children's Charity of St. Louis.
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. Mr. Crews serves on the Board of Directors of the St. Louis Regional Chamber. Mr. Crews has a Bachelor of Science degree in Accountancy from the University of Missouri at Columbia, a Master of Business Administration 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.; and a member of the Board of Directors of the St. Louis Zoo Association. She is also a member of the International Women's Forum/Missouri and the St. Louis

Forum. Ms. Fiehler holds a Master of Business Administration degree from the University of Missouri-St. Louis and bachelor degrees in psychology and social work from Southern Illinois University Edwardsville.

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Eric Ford was named our Chairman - Australia in October 2012. In this role he oversees all strategic aspects of the Australia platform, including business direction, commercial strategy and external stakeholder interaction. He served as President - Australia from March 2012 to October 2012 and as Executive Vice President and Chief Operating Officer from March 2007 to March 2012. 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. and as a Director of the Minerals Council of Australia. Mr. Ford was previously Deputy Chairman and a member of the Executive Committee of the Coal Industry Advisory Board of the International Energy Agency.

Christopher J. Hagedorn was named our President - Asia and Trading in March 2012. He has executive responsibility for our business and growth activities in Asia, including China, Mongolia, Indonesia and India; our global COALTRADE business, which includes global coal trading plus structured products and origination; Asian finance and administration; Asia business development activities; and the law function for Asia and Global Trading activities. He most recently served as our Senior Vice President Global Sales and Trading Support, and previously held positions with us of Senior Vice President, Chief Procurement Officer, and Vice President - Business Performance. Prior to joining us in August, 2006, he was an Associate Principal at McKinsey & Company in Cleveland, Ohio, where he provided management consulting services on various operations, marketing and business strategy topics to international clients in the energy, metals and mining, and chemicals sectors. Dr. Hagedorn holds a Bachelor of Science in chemical engineering from Washington University in St. Louis and a Doctorate in chemical engineering from the University of California - Santa Barbara. He is a member of the Board of Directors of the Sheldon Concert Hall in St. Louis.

Jeane L. Hull was named our Executive Vice President and Chief Technical Officer in March 2011. She joined us in May 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 Master of Business Administration degree from Nova University in Florida. Ms. Hull is a member of the University of Wyoming School of Energy Resources Council. She also serves on the University Advisory Board for South Dakota School of Mines and Technology, the Industry Advisory Board for Missouri University of Science and Technology Mining Department and the Washington University Olin Business School Women's Leadership Forum Steering Committee.

Charles F. Meintjes was named our President - Australia in October 2012. He has executive responsibility for our Australia operating platform, which includes overseeing the areas of health and safety, operations, sales and marketing, product delivery and support functions. Mr. Meintjes has extensive senior operational, strategy, continuous improvement and information technology experience with mining companies on three continents. He joined us in 2007, and most recently served as Acting President - Americas. Other past positions with us include Group Executive of Midwest and Colorado Operations, Senior Vice President of Operations Improvement and Senior Vice President Engineering and Continuous Improvement. Prior to joining us, Mr. Meintjes served as a consultant to Exxaro Resources Limited in South Africa, and is a former Executive Director and Board Member for Kumba Resources Limited in South Africa. He also served on the boards of two public companies, AST Gijima in South Africa and Ticor Limited in Australia, and has senior management experience in the steel and the aluminum industry with Iscor and Alusaf in South Africa. Mr. Meintjes holds dual Bachelor of Commerce degrees in accounting from Rand Afrikaans University and the University of South Africa. He is a Chartered Accountant in South Africa, and

completed the advanced management program at the University of Pennsylvania's Wharton School of Business.
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, on the Board of Directors of the National Blues Museum in St. Louis, Missouri, and on the Board of Directors of North Side Community School in St. Louis, Missouri.

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Kemal Williamson was named our President - Americas in October 2012. He has executive responsibility for our U.S. operating platform, a joint venture in Venezuela and business development activities. He oversees the areas of health and safety; operations; sales and marketing; product delivery; and support functions. Mr. Williamson has more than 30 years experience in mining engineering and operations roles across North America and Australia. He most recently served as Group Executive Operations for the Peabody Energy Australia operations. He also has held executive leadership roles across project development, as well as in positions overseeing our Western U.S., Powder River Basin and Midwest operations. Mr. Williamson joined us in 2000 as Director of Land Management. Prior to that, he served two years at Cyprus Australia Coal Corporation as Director of Operations and managed coal operations in Australia for half a decade. He also has mining engineering, financial analysis and management experience across Colorado, Kentucky and Illinois. Mr. Williamson holds a Bachelor of Science degree in mining engineering from Pennsylvania State University as well as a Master of Business Administration degree from the Kellogg School of Management, Northwestern University in Evanston, Illinois.

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.

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 Part I, Item 4. "Mine Safety Disclosures" 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 and Regulations

We are subject to various federal, state, local and tribal environmental laws and regulations. These laws and regulations place substantial requirements on our coal mining operations, and require regular inspection and monitoring of our mines and other facilities to ensure compliance. We are also affected by various other federal, state, local and tribal environmental laws and regulations that our customers are subject to.

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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 and 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 the OSM because the tribes do not have SMCRA authorization.

After 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. 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.

In situations where our coal resources are federally owned, the U.S. Bureau of Land Management oversees a substantive exploration and leasing process; if surface land is managed by the U.S. Forest Service, that agency serves as the cooperating agency during the federal coal leasing process. Federal coal leases also require an approved federal mining permit under the signature of the Assistant Secretary of the Department of the Interior.

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 amount can change periodically. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 to September 30, 2012, the fee was $0.315 and $0.135 per ton of surface-mined and underground-mined coal, respectively. From October 1, 2012 through September 30, 2021, the fee is $0.28 and $0.12 per ton of surface-mined and underground-mined coal, respectively.

The OSM is in the process of developing a “stream protection rule,” which could result in changes to surface mining regulations under the SMCRA program and will likely be proposed in 2013.

Clean Air Act. The Clean Air Act, enacted in 1970, and comparable state and tribal laws that regulate the emissions of materials into the air affect our 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 (PM), sulfur dioxide and ozone. It is possible that modifications to the national ambient air quality standards (NAAQS) could directly impact our mining operations in a manner that includes, but is not limited to, requiring changes in vehicle emissions standards or resulting in newly designated non-attainment areas. Furthermore, the Environmental Protection Agency (EPA) has recently adopted new rules to add more stringent PM emissions limits for coal preparation and processing plants constructed or modified after April 28, 2008.

The Clean Air Act indirectly, but more significantly, affects the U.S. coal industry by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury, PM and other substances emitted by coal-fueled electricity generating plants. The air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the Acid Rain Program, interstate transport rules, New Source Performance Standards, 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 U.S. EPA has adopted more stringent NAAQS for PM, nitrogen oxide and sulfur dioxide. The EPA has also proposed a more stringent ozone standard but withdrew it in 2011. That standard is due for reconsideration in 2013. Many of these programs and regulations have resulted in litigation which has not been completely resolved.

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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 motor vehicle engines are contributing to air pollution that are endangering public health and welfare within the meaning of the Clean Air Act. In May 2010, the EPA published final greenhouse gas emission standards for new motor vehicles pursuant to the Clean Air Act. Both the endangerment finding and motor vehicle standards are the subject of litigation. Because the Clean Air Act specifies that the prevention of significant deterioration (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." In a decision issued on June 26, 2012, the United States Court of Appeals affirmed the EPA's endangerment finding, its motor vehicle greenhouse gas rule and the tailoring rule. In a decision issued on December 20, 2012, the same court denied petitions to reconsider that decision. Petitions for review to the United States Supreme Court are expected.

New Source Performance Standards (NSPS). 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 NSPS for new and modified electric utility steam generating units under section 111(b) and 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. On April 13, 2012, the EPA published for comment the proposed NSPS for emissions of carbon dioxide for new fossil fuel-fired electric utility generating units. If these standards are adopted as proposed, it is unlikely, with a few possible exceptions, that any new coal-fired electric utility generating units could be constructed in the U.S. without the use of CCS technologies. The EPA has not yet finalized rules for modified or existing sources. Whatever the EPA determines the NSPS to be, those will then be the minimum requirements for best available control technology requirements under the PSD program. We believe that any final rules issued by the EPA in this area will be challenged. The EPA is required to finalize the 111(b) rule by April 2013 or re-propose a new rule for the same category.

Cross State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA finalized the 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 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 were to 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 the rule and advised that the EPA is expected to continue administering the Clean Air Interstate Rule (CAIR) until the pending challenges are resolved. The court vacated the CSAPR on August 21, 2012, in a 2 to 1 decision, concluding that the rule was beyond the EPA's statutory authority. On October 5, 2012, the EPA petitioned for en banc review of that decision by the entire U.S. Court of Appeals for the District of Columbia Circuit, which denied the EPA's petition on January 24, 2013.

Mercury and Air Toxic Standards (MATS). On December 16, 2011, the EPA issued the MATS, which imposes MACT emission limits on hazardous air emissions from new and existing coal-fueled electric generating plants. The rule also revised NSPS for nitrogen oxides, sulfur dioxides and PM for new and modified coal-fueled electricity generating plants. The MACT rule provides three years for compliance and a possible fourth year as a state permitting agency deems necessary. The final rule is the subject of pending litigation. On November 30, 2012, the EPA published proposed reconsidered MACT new plant standards that the EPA has indicated it will finalize in March 2013. These proposed reconsidered standards are less stringent in some aspects than the standards issued in December 2011.

Clean Water Act. The Clean Water Act of 1972 affects U.S. coal mining operations by requiring effluent limitations and treatment standards for wastewater discharge from mines through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting and performance standards are requirements of NPDES permits that govern the discharge of water from mine-related point sources into receiving waters.

The U.S. Army Corps of Engineers (Corps) regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the Clean Water Act requires mining companies to obtain Corps permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities.

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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.

The EPA and other agencies are currently considering whether to finalize draft guidance on identifying waters protected by the Clean Water Act, or to initiate a rulemaking to codify the policy. It is possible that both issuance of finalized guidance and initiation of a rulemaking may be undertaken. This undertaking may occur in 2013. Direct impact on coal mining operations may result from either of these agency priorities.

National Environmental Policy Act (NEPA). NEPA, signed into law in 1970, requires federal agencies to review the environmental impacts of their decisions and issue either an environmental assessment or an environmental impact statement. We must provide information to agencies when we propose actions that will be under the authority of the federal government. The NEPA process involves public participation and sometimes lengthy timeframes.

Resource Conservation and Recovery Act (RCRA). 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 May 2000, the EPA concluded that coal combustion materials do not warrant regulation as hazardous wastes under RCRA and retained the hazardous waste exemption for these materials. 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. This determination is due in 2013. The OSM is also tasked with regulating CCRs at coal mines and is currently working on a rule, which is expected to be proposed in 2013.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Although typically not applied to the coal mining sector, CERCLA, which was enacted in 1980, nonetheless does affect 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.

Toxic Release Inventory. Under the EPA's Toxic Release Inventory program, arising out of the passage of the Emergency Planning and Community Right-to-Know Act in 1986 and the Pollution Prevention Act passed in 1990, companies are required annually to report the use, manufacture or processing of listed toxic materials that exceed defined thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers.

Endangered Species Act (ESA). The ESA of 1973 and counterpart state legislation is intended to protect species whose populations allow for categorization as either endangered or threatened. Changes in listings or requirements under these regulations 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. The U.S. Bureau of Alcohol, Tobacco and Firearms (ATF) regulates the use of explosive blasting materials. In addition to ATF regulation, the Department of Homeland Security (DHS) is planning to finalize its proposed ammonium nitrate security program in 2013. This proposed DHS program may not exempt those facilities producing, selling or purchasing ammonium nitrate “exclusively for use in the production of explosives under license or permit issued” under the existing ATF regulations. If the program is finalized and the aforementioned exemption is not granted, direct impact to coal mining operations may occur.

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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 (for example, an endangered species or particular protected places). Environmental approvals processes involve complex issues that, on occasion, require lengthy studies and documentation.

Our Australian mining operations are generally subject to local, state and federal laws and regulations. At the federal level, these legislative acts include, but are not limited to, the Environment Protection and Biodiversity Act 1999, Native Title Act 1993, Australian Heritage Council Act 2003 and the Aboriginal and Torres Strait Islander Heritage Protection Act 1984.

In Queensland, laws and regulations related to mining include, but are not limited to, the Mineral Resources Act 1989, Environmental Protection Act 1994 (EP Act), Environmental Protection Regulation 1998, Integrated Planning Act 1997, Building Act 1975, Explosives Act 1999, Aboriginal Cultural Heritage Act 2003, Water Act 2000, State Development and Public Works Organisation Act 1971, Queensland Heritage Act 1992, Transport Infrastructure Act 1994, Nature Conservation Act 1992, Vegetation Management Act 1999, Land Protection (Pest and Stock Route Management) Act 2002, Land Act 1994, Fisheries Act 1994 and Forestry Act 1959. Under the EP Act, policies have been developed to achieve the objectives of the law and provide guidance on specific areas of the environment, including air, noise, water and waste management. State planning policies address matters of Queensland State interest, and must be adhered to during mining project approvals. Increased emphasis has recently been placed on topics including, but not limited to, hazardous dams assessment and the protection of strategic cropping land.

In New South Wales, laws and regulations related to mining include, but are not limited to, the Mining Act 1992, Coal Mines Regulation Act 1982, Mine Subsidence Compensation Act 1961, Environmental Planning and Assessment Act 1979 (EP&A Act), Environmental Planning and Assessment Regulations 2000, Protection of the Environment Operations Act 1997, Contaminated Land Management Act 1997, Explosives Act 2003, Water Management Act 2000, Water Act 1912, Radiation Control Act 1990, Heritage Act 1977, Aboriginal Land Rights Act 1983, Crown Lands Act 1989, Dangerous Goods Act 2008, Fisheries Management Act 1994, Forestry Act 1916, Native Title (New South Wales) Act 1994, Native Vegetation Act 2003, Noxious Weeds Act 1993, Roads Act 1993, and National Parks & Wildlife Act 1974. Under the EP&A Act, environmental planning instrument provisions must be taken into consideration. There are multiple State Environmental Planning Policies (SEPPs) relevant to coal projects in New South Wales. Amendments to the SEPPs related to mining are surrounding the protection of agriculture, water resources and critical industry clusters are under consideration.

Occupational Health and Safety. Various state and federal legislation requires us to ensure that persons employed in our mines 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. General statutes for work health and safety have been enacted at the state, territorial and federal level. In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under varying state legislation specific to the coal mining industry. There are some differences in the application and detail of the laws, and mining employers, owners, directors and managers, persons in control of work places, mine managers, supervisors and employees are all subject to these duties.

The National Mine Safety Framework is a current initiative aiming to achieve a nationally consistent occupational health and safety regime in the Australian mining industry through mine safety model regulations and core and non-core legislative changes. The initiative is not yet finalized, but is projected to commence in 2013.

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

National Greenhouse and Energy Reporting Act 2007 (NGER Act). In 2007, a single, national reporting system relating to greenhouse gas emissions, energy use and energy production was introduced. The NGER Act imposes requirements for corporations meeting a certain threshold to register and report greenhouse gas emissions and abatement actions, as well as energy production and consumption. Information collected through this system provides the basis for assessing liability under a carbon pricing mechanism. The Clean Energy Regulatory administers the NGER Act. The Department of Climate Change and Energy Efficiency is responsible for NGER Act-related policy developments and review. Both foreign and local corporations that meet the prescribed carbon dioxide 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 annually on the greenhouse gas emissions and energy production and consumption of our Australian entities.

Queensland Royalty. In September 2012, the State of Queensland announced new royalty rates on coal prices. The royalty change went into effect on October 1, 2012 and raised the royalty payment to the State of Queensland on coal prices over $100 per tonne from 10% to 12.5% for pricing up to $150 per tonne and 15% on pricing over $150 per tonne. There was no change to the 7% rate for coal sold below $100 per tonne. The impact of these new royalty rates will depend upon the volume of tonnes produced at each of our Queensland mining locations and coal prices received on those tonnes.

Carbon Pricing Framework. The Australian government's carbon pricing framework commenced on 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 average $1.00 to $2.00 Australian dollars per tonne of coal produced annually. Actual results will depend upon the volume of tonnes produced at each of our Australian 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 have applied 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 five-year period. Those sites received payments totaling $22.5 million Australian dollars in June 2012 related to this program, with similar payments expected in each of the next four years.. We also may be eligible for a portion of the government's $70 million Australian dollars Coal Mining Abatement Technology Support Package over five years to support the development and deployment of technologies to reduce fugitive emissions from coal mines. Net of transition benefits, we recognized expenses of $11.9 million Australian dollars in 2012 related to this program, all of which was incurred in second half of that year.

Minerals Resource Rent Tax. On March 29, 2012, Australia passed legislation creating a minerals resource rent tax (the MRRT) effective from July 1, 2012. The MRRT is a profits-based tax of our existing and future Australian coal projects at an effective tax rate of 22.5%. Under the MRRT, taxpayers are able to elect a market value asset starting base for existing projects which allows for the fair market value of the tenements to be deducted over the life of the mine as an allowance against MRRT. The market value allowance, and ultimately any future benefit, is subject to numerous uncertainties, including review and approval by the Australian Tax Office, realization only after other MRRT allowances provided under the law and estimates of long-term pricing and cost data necessary to estimate the future benefit and any MRRT liability. We have evaluated the provisions of the new tax and assessed recoverability of deferred tax assets and the valuation of liabilities associated with the implementation of the MRRT. As of December 31, 2012, we have recorded a net deferred tax liability of $77.2 million related to the market value starting base. Refer to Note 10. "Income Taxes" to the accompanying consolidated financial statements for additional information related to the implementation of the MRRT in 2012.

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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 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 (RGGI) 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. It has been reported that, while the MGGRA has not been formally suspended, the participating states are no longer pursuing it. 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. Of those five jurisdictions, only California and Quebec have adopted greenhouse gas cap-and-trade regulations to date and both programs have begun operating. Many of the states and provinces that left WCI, RGGI and MGGRA, along with many that continue to participate, have joined the new North America 2050 initiative, which seeks to reduce greenhouse gas emissions and create economic opportunities in ways not limited to cap-and-trade programs.

In the U.S., several states have enacted legislation establishing greenhouse gas emissions reduction goals or requirements. In addition, several states have enacted legislation or have in effect regulations 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 Department of Energy'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, the Durban meeting in late 2011 and the Doha meeting in late 2012. At the Doha meeting, an amendment to the Kyoto Protocol was adopted, which includes new commitments for certain parties in a second commitment period, from 2013 to 2020.

Australia's Parliament passed carbon pricing legislation in November 2011. The first three years of the program involve the imposition of a carbon tax that commenced in July 2012 and a mandatory greenhouse gas emissions trading program commencing in 2015.

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.

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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.

Available Information

We file or furnish annual, quarterly and current reports (including any exhibits or amendments to those reports), proxy statements and other information with the SEC. These materials are available free of charge through our website (www.peabodyenergy.com) as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information included on our website does not constitute part of this document. These materials may also be accessed through the SEC's website (www.sec.gov) or in the SEC’s Public Reference Room located at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling 1-800-SEC-0330.

In addition, copies of our filings will be made available, free of charge, upon request 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.

Item 1A.   Risk Factors.

We operate in a rapidly changing environment that involves a number of risks. The following discussion highlights some of these risks and others are discussed elsewhere in this report. These and other risks could materially and adversely affect our business, financial condition, prospects, operating results or cash flows. The following risk factors are not an exhaustive list of the risks associated with our business. New factors may emerge or changes to these risks could occur that could materially affect our business.

Risks Associated with Our Operations

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, quality and price of alternative fuels, including natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power;
- the proximity, capacity and cost of transportation and terminal facilities;
- coal industry capacity;
- 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 related to alternative energy sources, 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.

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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 2012, 89% of our worldwide sales volume was sold under long-term coal supply agreements. At January 1, 2013, our sales backlog, including backlog subject to price reopener and/or extension provisions, was approximately 900 million tons, representing nearly four years of current production in backlog based on our 2012 production from continuing operations of 225.7 million tons. Contracts in backlog have remaining terms ranging up to 15 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.

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, 2012 we derived 26% of our total coal sales revenues from our five largest customers. Those five customers were supplied primarily from 44 coal supply agreements (excluding trading transactions) expiring at various times from 2013 to 2026. The contract contributing the greatest amount of annual revenue in 2012 was approximately $320 million, or approximately 5% of our 2012 total coal sales 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, if coal prices continue at levels experienced in late 2012 or if there are further 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 challenging economic and financial conditions.

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

Our ability to receive payment for coal sold and delivered or for financially settled contracts depends on the continued creditworthiness and contractual performance 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 or they fail to perform the terms of their contracts with us, 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, 2012, certain coal supply agreements permit the customer to terminate the contract if the cost of transportation increases by an amount over specified levels in any given 12-month period.

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

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

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

Take-or-pay arrangements within the coal industry could significantly affect our costs and demand for coal.

We have substantial take-or-pay arrangements totaling $4.4 billion, with terms ranging up to 28 years, that commit us to pay a minimum amount for rail and port commitments for the delivery of coal even if those commitments go unused. The take-or-pay provisions in these contracts allow us to subsequently apply take-or-pay payments made to deliveries subsequently taken, but these provisions have limitations and we may not be able to utilize all such amounts paid if the limitations apply or if we do not subsequently take sufficient volumes to utilize the amounts previously paid. Additionally, coal companies, including us, may continue to deliver coal during times when it might otherwise be optimal to suspend operations because these take-or-pay provisions effectively convert a marginal cost of selling coal to a fixed operating cost.

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An inability of trading, brokerage, mining or freight counterparties to fulfill the 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 2012 volume came from mines that utilize contract miners, with conversions of certain of those mines to owner-operated status expected to be completed in 2013. 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 would 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.

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 expose 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, 2012, we had approximately 8,200 employees, which included approximately 5,700 hourly employees. Approximately 30% of our hourly employees were represented by organized labor unions and generated 19% of 2012 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, 2012, we had $1,275.8 million of self bonding in place for our reclamation obligations. As of December 31, 2012, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of $995.8 million, of which $571.6 million was for post-mining reclamation, $53.5 million related to workers' compensation obligations, $105.3 million was for coal lease obligations and $265.4 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.

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.

Governmental 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 governmental 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 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.

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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 24. "Commitments and Contingencies" to our consolidated financial statements for a description of pending legal proceedings involving Gold Fields.

Our mining operations are subject to extensive forms of taxation, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal competitively.

Federal, state, provincial or local governmental authorities in nearly all countries across the global coal mining industry impose various forms of taxation, including production taxes, sales-related taxes, royalties, environmental taxes, mining profits taxes and income taxes. If new legislation or regulations related to various forms of coal taxation, which increase our costs or limits our ability to compete in the areas in which we sell our coal, are adopted, our business, financial condition or results of operations could be adversely affected.

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

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

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

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Moreover, the amount of proven and probable coal reserves described in Part I, 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, 2012, we leased a total of 75,100 acres from the federal government subject to those limitations. The limit could restrict our ability to lease additional U.S. federal lands.

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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.

We are exposed to significant liability, reputational harm, loss of revenue, increased costs or other risks if we sustain cyber attacks or other security breaches that disrupt our operations or result in the dissemination of proprietary or confidential information about us, our customers or other third-parties.

We have implemented security protocols and systems with the intent of maintaining the physical security of our operations and protecting our and our counterparties' confidential information and information related to identifiable individuals against unauthorized access. Despite such efforts, we may be subject to security breaches which could result in unauthorized access to our facilities or the information we are trying to protect. Unauthorized physical access to one of our facilities or electronic access to our information systems could result in, among other things, unfavorable publicity, litigation by affected parties, damage to sources of competitive advantage, disruptions to our operations, loss of customers, financial obligations for damages related to the theft or misuse of such information and costs to remediate such security vulnerabilities, any of which could have a substantial impact on our results of operations, financial condition or cash flows.

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, 2012, we had $1.5 billion of maximum borrowing capacity under the Revolver portion of our Credit Facility and $1.4 billion of available capacity under that 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.

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Our financial performance could be adversely affected by our debt.

As of December 31, 2012, our total indebtedness was $6.3 billion, and we had $1.4 billion of maximum 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 or other general corporate requirements;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, business development 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.

Any downgrade in our credit ratings could result in 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 and 2011 Term Loan 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. If we do not remain in compliance with the covenants associated with our Credit Facility and 2011 Term Loan Facility, we may be restricted in our ability to pay dividends, sell assets and make redemptions or repurchase capital stock. Also, because our ability to borrow under the Credit Facility is conditioned upon compliance with these covenants, our actual borrowing capacity under the Credit Facility at any time may be less than the maximum borrowing capacity.

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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 occurrence of a mandatory trigger event with respect to our Debentures would affect our ability to pay dividends on our common stock.

Our failure to meet certain financial covenants contained in the indenture governing the Debentures would result in a mandatory trigger event (as defined therein). If a mandatory trigger event has occurred and is continuing, we may not pay interest on the Debentures unless we obtain funds for such payment through the sale of qualifying warrants or qualifying preferred stock. During any mandatory deferral period, we will generally be prohibited from declaring or paying any dividends on, or making any distributions regarding, or redeeming, purchasing, acquiring or making liquidation payments with respect to our common stock.

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.

On July 9, 2012, Patriot and certain of its wholly owned subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code. Patriot is responsible for certain federal and state black lung occupational disease liabilities, which are expected to be less than $150 million, as well as related credit capacity in support of these liabilities. Should Patriot not fund these obligations as they become due, we could be responsible for such costs when incurred.

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

We provide postretirement health and life insurance benefits to eligible union and non-union employees. We calculated the total accumulated postretirement benefit obligation, which was a liability of $1,026.1 million as of December 31, 2012, $65.4 million of which was a current liability. Net pension liabilities were $244.9 million as of December 31, 2012, $1.7 million of which was a current liability.

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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. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock and may have the effect of delaying or preventing a change in control.

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

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

Item 1B. Unresolved Staff Comments.

None.

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Item 2. Properties.

Coal Reserves

We had an estimated 9.3 billion tons of proven and probable coal reserves as of December 31, 2012. An estimated 8.2 billion tons of our attributable proven and probable coal reserves are in the U.S, with the remainder in Australia. Approximately 52% of our Australian proven and probable coal reserves, or 580 million tons, are metallurgical coal with the remainder being thermal coal. Approximately 52% of our reserves, or 4.8 billion tons, are compliance coal and 48% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). We own approximately 37% of these reserves and lease property containing the remaining 63%. 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 proven and probable coal reserves of our major operating regions.

		Proven and Probable Reserves as of December 31, 2012[1]		
Operating Regions	Locations	Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	2,585	823	3,408
Powder River Basin	Wyoming	28	3,528	3,556
Southwest	Arizona and New Mexico	738	267	1,005
Colorado	Colorado	44	160	204
Total United States		3,395	4,778	8,173
Australia	New South Wales	—	339	339
Australia	Queensland	—	773	773
Total Australia		—	1,112	1,112
Total Proven and Probable Coal Reserves		3,395	5,890	9,285

(1) Estimated proven and probable coal reserves have been adjusted to account for estimated processing losses involved in producing a saleable coal product.

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

- Proven (Measured) Reserves — Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so close and the geographic character is so well defined that size, shape, depth and mineral content of reserves are well-established.
- Probable (Indicated) Reserves — Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our estimates of proven and probable coal reserves are established within these guidelines. 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.

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Our guidelines for geologic assurance surrounding estimated proven and probable U.S. and Australian coal reserves generally follow the respective industry-accepted practices of those countries. In the U.S., our estimated proven coal reserves lie within one-quarter mile of a valid point of measure or point of observation, such as exploratory drill holes or previously mined areas, while our estimated probable coal reserves may lie more than one-quarter mile, but less than three-quarters of a mile, from a point of thickness measurement. In Australia, our estimated proven coal reserves lie within 250 meters of a point of observation, while our estimated probable coal reserves may lie more than 250 meters, but less than 500 meters, from a point of observation.

The preparation of our coal reserve estimates are completed in accordance with our prescribed internal control procedures, which include verification of input data into a coal reserve forecasting and economic evaluation software system, as well as multi-functional management review. 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 coal reserve estimates are predicated on information obtained from our ongoing drilling program, which is comprised of 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 a drill pattern determines whether the related coal reserves will be classified as proven or probable. Our coal reserve estimates are then input into our computerized land management system, which overlays that geological data with data on ownership or control of the mineral and surface interests to determine the extent of our attributable coal reserves in a given area. Our 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 coal reserve estimates to reflect production of coal from those reserves and new drilling or other data received. Accordingly, our coal reserve estimates will change from time to time to reflect the effects of our mining activities, analysis of new engineering and geological data, changes in coal reserve holdings, modification of mining methods and other factors.

Our estimate of the economic recoverability of our coal 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 take into consideration typical contractual sales agreements for the region and product. Where possible, we also review coal production by competitors in similar mining areas. Only coal reserves expected to be mined economically are included in our reserve estimates. Finally, our coal 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 coal 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 the Powder River Basin and other reserves in 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, 2012, we leased 11,936 acres of federal land in Colorado, 11,254 acres in Montana and 51,910 acres in Wyoming, for a total of 75,100 nationwide subject to those limitations.

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.

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.

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

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The following charts provide a summary, by mining complex, of production for the years ended December 31, 2012, 2011 and 2010, tonnage of coal reserves that is assigned to our active operating mines, our property interest in those reserves and other characteristics of the facilities.

SUMMARY OF COAL PRODUCTION AND SULFUR CONTENT OF ASSIGNED RESERVES
(Tons in Millions)

	Production				Sulfur Content of Assigned Reserves as of Dec. 31, 2012 (1)			
	Year	Year	Year		<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	As
	Ended	Ended	Ended		Sulfur	Sulfur	Sulfur	Received
Geographic Region /	Dec. 31,	Dec. 31,	Dec. 31,	Type of	Dioxide per	Dioxide per	Dioxide per	Btu per
Mining Complex	2012	2011	2010	Coal	Million Btu	Million Btu	Million Btu	pound (2)
Midwest:								
Bear Run	7.9	6.5	2.8	T	5	28	242	11,500
Gateway	2.8	3.3	3.2	T	—	—	6	11,000
Francisco Underground	2.8	3.0	2.7	T	—	—	49	11,500
Somerville Central	2.3	3.0	3.4	T	—	—	5	11,500
Willow Lake (Closed in 2012)	2.1	2.2	2.9	T	—	—	—	NA
Cottage Grove	2.0	1.9	2.1	T	—	—	19	12,600
Wild Boar	2.0	1.8	0.1	T	—	—	13	11,000
Somerville South	1.4	1.2	1.7	T	—	—	6	11,100
Wildcat Hills Underground	1.5	1.0	0.8	T	—	—	27	12,100
Viking - Corning Pit	1.3	1.5	1.5	T	—	—	2	11,500
Somerville North	1.2	1.4	2.0	T	—	—	3	11,000
Viking - Knox Pit (Closed in 2010)	—	—	1.7	T	—	—	—	NA
Farmersburg (Closed in 2010)	—	—	1.5	T	—	—	—	NA
Total	27.3	26.8	26.4		5	28	372	
Powder River Basin:								
North Antelope Rochelle	107.6	109.1	105.8	T	2,364	—	—	8,800
Caballo	16.9	24.1	23.5	T	713	119	20	8,300
Rawhide	14.7	15.0	11.2	T	250	60	2	8,200
Total	139.2	148.2	140.5		3,327	179	22	
Southwest:								
Kayenta	7.5	8.1	7.8	T	162	67	2	10,600
El Segundo	8.6	8.1	6.6	T	26	71	71	9,100
Lee Ranch	1.3	2.0	1.6	T	18	113	13	9,300
Total	17.4	18.2	16.0		206	251	86	
Colorado:								
Twentymile	8.0	7.7	7.7	T	34	—	—	11,300
Australia:								
Wilpinjong	12.2	10.9	9.6	T	—	179	—	11,200
Wambo (3)	6.6	5.8	6.6	T/P	124	—	—	12,200

North Goonyella / Eaglefield	4.1	2.2	3.2	M	121	—	—	12,900
Burton	1.2	2.1	2.5	T/M	14	—	—	12,700
Millennium	3.2	1.9	1.6	M/P	29	—	—	12,600
Metropolitan	1.8	1.8	1.6	M	36	—	—	12,600
Coppabella	2.8	0.4	—	P	55	—	—	12,700
Moorvale	1.9	0.3	—	M/P	18	—	—	12,100
Middlemount (4)	—	—	—	T/M/P	37	—	—	12,300
Total	33.8	25.4	25.1		434	179	—	
Total Continuing Operations	225.7	226.3	215.7		4,006	637	480	
Discontinued Operations	3.3	2.6	2.7		—	—	—	
Total Assigned	229.0	228.9	218.4		4,006	637	480	

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection

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ASSIGNED RESERVES [5]
AS OF DECEMBER 31, 2012

(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%	275	125	150	275	—	275	125	150	275	—
Francisco Underground	100%	49	10	39	—	49	49	10	39	—	49
Wildcat Hills Underground	100%	27	16	11	—	27	27	16	11	—	27
Cottage Grove	100%	19	10	9	19	—	19	10	9	19	—
Wild Boar	100%	13	10	3	13	—	13	10	3	13	—
Gateway	100%	6	5	1	—	6	6	5	1	—	6
Somerville South	100%	6	5	1	6	—	6	5	1	6	—
Somerville Central	100%	5	4	1	5	—	5	4	1	5	—
Somerville North	100%	3	1	2	3	—	3	1	2	3	—
Viking - Corning Pit	100%	2	—	2	2	—	2	—	2	2	—
Total		405	186	219	323	82					
Powder River Basin:											
North Antelope Rochelle	100%	2,364	—	2,364	2,364	—	2,364	—	2,364	2,364	—
Caballo	100%	852	—	852	852	—	852	—	852	852	—
Rawhide	100%	312	—	312	312	—	312	—	312	312	—
Total		3,528	—	3,528	3,528	—					
Southwest:											
Kayenta	100%	232	—	232	232	—	232	—	232	232	—
El Segundo	100%	167	154	13	167	—	167	154	13	167	—
Lee Ranch	100%	144	123	21	144	—	144	123	21	144	—
Total		543	277	266	543	—					
Colorado:											
Twentymile	100%	34	7	27	—	34	34	7	27	—	34
Australia:											
Wilpinjong	100%	179	—	179	179	—	179	—	179	179	—
Wambo [3]	100%	124	—	124	47	77	124	—	124	47	77
North Goonyella / Eaglefield	100%	121	—	121	3	118	121	—	121	3	118

Coppabella	73.3%	55	—	55	29	26	75	—	75	40	35
Millennium	100%	29	—	29	29	—	29	—	29	29	—
Burton	100%	14	—	14	14	—	14	—	14	14	—
Metropolitan	100%	36	—	36	—	36	36	—	36	—	36
Moorvale	73.3%	18	—	18	18	—	25	—	25	25	—
Middlemount [4]	50.0%	37	—	37	37	—	74	—	74	74	—
Total		613	—	613	356	257					
Total Assigned		5,123	470	4,653	4,750	373					

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES
AS OF DECEMBER 31, 2012
(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	52	2,233	2,285	1,120	1,165	52	2,233	2,285	1,120	1,165
Indiana	353	318	671	527	144	353	318	671	527	144
Kentucky	—	452	452	237	215	—	452	452	237	215
Total	405	3,003	3,408	1,884	1,524					
Powder River Basin (Wyoming)	3,528	28	3,556	3,208	348	3,528	28	3,556	3,208	348
Southwest:										
Arizona	232	—	232	232	—	232	—	232	232	—
New Mexico	311	462	773	718	55	311	462	773	718	55
Total	543	462	1,005	950	55					
Colorado	34	170	204	126	78	34	170	204	126	78
Australia:										
New South Wales	339	—	339	270	69	339	—	339	270	69
Queensland (6)	274	499	773	570	203	338	535	873	611	262
Total	613	499	1,112	840	272					
Total Proven and Probable	5,123	4,162	9,285	7,008	2,277					

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ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2012
(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	1,916	369	76	2,209	1,916	369	76	2,209
Indiana	374	297	458	213	374	297	458	213
Kentucky	295	157	89	363	295	157	89	363
Total	2,585	823	623	2,785				
Powder River Basin (Wyoming)	28	3,528	3,556	—	28	3,528	3,556	—
Southwest:								
Arizona	—	232	232	—	—	232	232	—
New Mexico	738	35	745	28	738	35	745	28
Total	738	267	977	28				
Colorado	44	160	—	204	44	160	—	204
Australia:								
New South Wales	—	339	226	113	—	339	226	113
Queensland (6)	—	773	629	144	—	873	705	168
Total	—	1,112	855	257				
Total Proven and Probable	3,395	5,890	6,011	3,274				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2012
(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	—	—	2,285	—	—	2,285	10,300
Indiana	T	5	37	629	5	37	629	10,200
Kentucky	T	—	—	452	—	—	452	10,900
Total		5	37	3,366				
Powder River Basin (Wyoming)	T	3,350	184	22	3,350	184	22	8,700
Southwest:								
Arizona	T	162	68	2	162	68	2	11,000
New Mexico	T	159	382	232	159	382	232	9,400
Total		321	450	234				
Colorado	T	190	—	14	190	—	14	10,700
Australia:								
New South Wales	T/M/P	160	179	—	160	179	—	11,800
Queensland (6)	T/M/P	773	—	—	873	—	—	12,100
Total		933	179	—				
Total Proven and Probable		4,799	850	3,636				

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection

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(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.

(5) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2012. 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 include approximately 146 million tons of reserves held for sale associated with our Wilkie Creek Mine.

Item 3. Legal Proceedings.

See Note 24. "Commitments and Contingencies" to our consolidated financial statements for a description of our pending legal proceedings, which information 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 our 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 the Mine Safety and Health Administration (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 accountable for their safety and the safety of other employees.

We also partner with other companies and certain governmental agencies to pursue new technologies that have the potential to improve our safety performance and provide better safety protection for employees. We are working with E-Spectrum Technologies, Inc. and the National Institute for Occupational Safety and Health to test the Rescue Dog emergency system at our Twentymile Mine in Colorado. The Rescue Dog system uses low frequency, through-the-earth signal technology purportedly capable of communication for mining sections at depths in excess of 2,000 feet underground.

In April 2012, we announced our endorsement and participation in CORESafety, a new safety and health management system developed by member companies of the National Mining Association for the U.S. mining industry. CORESafety is an approach to safety and health focused on preventing accidents through the use of a management system that focuses on leadership development, management processes, individual accountability and assurance techniques. Its objective is to have zero fatalities and a 50% reduction in mining's injury rate within five years.

The incidence rate, which is monitored through our safety tracking system, is a measure of safety performance which represents the number of injuries that occurred for each 200,000 employee hours worked. Accordingly, it is computed as the number of injury occurrences, MSHA reportable injury degree codes 1 through 6, divided by the number employee hours worked and multiplied by 200,000 [(number of injury occurrences ÷ number of employee hours worked) x 200,000]. Since MSHA is a branch of the U.S. Department of Labor, its jurisdiction applies only to our U.S. mines. Nonetheless, we also track incidence rates for our Australian mines in order to measure safety performance on a consistent basis across our global mining operations.

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For the U.S., the most comparable industry measure with which to compare our safety performance is the all incidence rate for operators at all U.S. bituminous coal mines, excluding the impact of office workers, from MSHA's periodic Mine Injury and Worktime report (All Incidence Rate). Historical incidence rates may be adjusted over time to reflect the final resolution of incidents by MSHA. The impact of these adjustments, which has not historically resulted in significant changes to the results originally reported, is reflected retrospectively in the MSHA database. Similarly, our reported incidence rates are adjusted retrospectively to reflect the final resolution of the underlying incidents, when applicable.

The following table reflects our incidence rates and most comparable industry measure:

	Year Ended December 31,		
	2012	2011	2010
MSHA (U.S. coal mines)[(1)]	3.50	3.76	3.91
U.S.[(2)]	1.28	1.50	2.05
Australia[(2)]	2.50	2.77	4.03
Total Peabody Energy Corporation[(2)]	1.87	2.00	2.75

[(1)] The 2012 MSHA all incidence rate for operators at all U.S. bituminous coal mines, excluding the impact of office workers, reflected above represents preliminary results for January through December 2012 based on the data most recently published by MSHA as of February 20, 2013.

[(2)] Results for the years ended December 31, 2011 and 2010 exclude PEA-PCI, previously Macarthur Coal Limited. Results for all periods presented in the table above include our Air Quality Mine and Wilkie Creek Mine, which were previously components of our Midwestern U.S. Mining and Australian Mining segments, respectively, and classified as discontinued operations as of December 31, 2012. Excluding the impact of those discontinued operations, our 2012 incidence rates for the U.S., Australia and worldwide were 1.19, 2.50 and 1.82, respectively.

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. Similar to historical incidence rates, historical violations per inspection day may be adjusted over time to reflect the final resolution of the underlying matters. For the years ended December 31, 2012, 2011 and 2010, our U.S. violations per inspection day were 0.79, 0.82 and 0.88, respectively.

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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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 15, 2013, there were 1,406 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 and the amount of cash dividends paid per share of our common stock during the calendar quarters indicated.

	Share Price		Dividends
	High	Low	Paid
2012			
First Quarter	$38.90	$28.83	$0.085
Second Quarter	31.59	21.12	0.085
Third Quarter	26.21	19.05	0.085
Fourth Quarter	29.28	21.81	0.085
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

Dividend Policy

We have declared and paid quarterly dividends since our initial public offering in 2001. In January 2013, our Board of Directors declared a dividend of $0.085 per share of Common Stock, payable on February 28, 2013, to stockholders of record on February 7, 2013. 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 Part II, 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 approved an amendment to the share repurchase program authorizing up to $1.0 billion of the then outstanding shares of our common stock (Repurchase Program). Repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. The Repurchase Program does not have an expiration date and may be discontinued at any time. Through December 31, 2012, we have repurchased a total of 7.7 million shares under the Repurchase Program at a cost of $299.6 million ($199.8 million in 2008 and $99.8 million in 2006), leaving $700.4 million available for share repurchases under the Repurchase Program. No share repurchases were made under the Repurchase Program during the years ended December 31, 2012, 2011 or 2010.

Our Chairman and Chief Executive Officer has the authority to direct the repurchase of up to $100.0 million of our common stock outside the Repurchase Program. During the second quarter of 2012, we repurchased $99.9 million, or 4.2 million shares, of our outstanding common stock pursuant to this authority through open-market transactions.

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The following table summarizes all share repurchases for the three months ended December 31, 2012:

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, 2012	3,121	$22.63	—	$700.4
November 1 through November 30, 2012	1,508	26.54	—	700.4
December 1 through December 31, 2012	—	—	—	700.4
Total	4,629	$23.90	—	

(1) Represents shares withheld to cover the withholding taxes upon the vesting of restricted stock, which are not a part of the 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 2012, 2011 and 2010 in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" includes references to and analysis of Adjusted EBITDA, Adjusted Income from Continuing Operations and Adjusted Diluted EPS, which are financial measures not recognized in accordance with U.S. generally accepted accounting principles (GAAP). These financial measures are not intended to serve as alternatives to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies. Beginning with this report, we have modified the definitions of these non-GAAP financial measures to also exclude the impact of asset impairment and mine closure costs because we believe that excluding these impacts is useful in comparing the our 2012 results with those of prior and future periods.

Adjusted EBITDA is defined as income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expense, depreciation, depletion and amortization, asset impairment and mine closure costs and amortization of basis difference associated with equity method investments. Adjusted EBITDA is used by management to measure our segments' operating performance and we believe it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Adjusted Income from Continuing Operations and Adjusted Diluted EPS are defined as income from continuing operations and diluted earnings per share from continuing operations (EPS), respectively, excluding the impacts of asset impairment and mine closure costs, net of tax, and the remeasurement of foreign income tax accounts on our income tax provision. The income tax benefits related to asset impairment and mine closure costs have been calculated based on the enacted tax rate in the jurisdiction in which they have been or will be realized, adjusted for the estimated recoverability of those benefits. We have included Adjusted Income from Continuing Operations and Adjusted Diluted EPS in our discussion because, in the opinion of management, excluding those foregoing items is useful in comparing our current results with those of prior periods. We also believe that excluding the impact of the remeasurement of our foreign income tax accounts represents a meaningful indicator of our ongoing effective tax rate.

Reconciliations of Adjusted EBITDA, Adjusted Income from Continuing Operations and Adjusted Diluted EPS to their most comparable measures under U.S. GAAP are included below.

The selected financial data for all periods presented reflect the classification as discontinued operations of certain operations previously divested (by sale or otherwise), as well as certain non-strategic mining assets held for sale where we have committed to the divestiture of such assets.

On October 26, 2011, we acquired Macarthur Coal Limited (PEA-PCI). Our results of operations include PEA-PCI's results of operations from that date. Refer to Note 2. "Acquisition of Macarthur Coal Limited" to the accompanying consolidated financial statements for additional details surrounding that business combination.

We have derived the selected historical financial data as of and for the years ended December 31, 2012, 2011, 2010, 2009 and 2008 from our audited financial statements, adjusted retrospectively for items subsequently classified as discontinued operations and the implementation of certain accounting literature. The following table should be read in conjunction with the accompanying financial statements, including the related notes to those financial statements, and Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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The results of operations for the historical periods included in the following table are not necessarily indicative of the results to be expected for future periods. In addition, the Risk Factors section of Part I, 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,				
	2012	2011	2010	2009	2008
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	$8,077.5	$7,895.9	$6,668.2	$5,746.4	$6,237.6
Costs and expenses	7,905.0	6,300.2	5,317.1	4,919.6	4,944.3
Operating profit	172.5	1,595.7	1,351.1	826.8	1,293.3
Interest expense, net	381.1	219.7	212.4	193.0	217.1
(Loss) income from continuing operations before income taxes	(208.6)	1,376.0	1,138.7	633.8	1,076.2
Income tax provision	262.3	363.2	313.7	187.8	163.9
(Loss) income from continuing operations, net of income taxes	(470.9)	1,012.8	825.0	446.0	912.3
(Loss) income from discontinued operations, net of income taxes	(104.2)	(66.5)	(22.8)	17.0	46.8
Net (loss) income	(575.1)	946.3	802.2	463.0	959.1
Less: Net income (loss) attributable to noncontrolling interests	10.6	(11.4)	28.2	14.8	6.2
Net (loss) income attributable to common stockholders	$(585.7)	$957.7	$774.0	$448.2	$952.9
Basic earnings per share from continuing operations	$(1.80)	$3.78	$2.96	$1.61	$3.35
Diluted earnings per share from continuing operations	$(1.80)	$3.77	$2.92	$1.60	$3.33
Weighted average shares used in calculating basic earnings per share	268.0	269.1	267.0	265.5	268.9
Weighted average shares used in calculating diluted earnings per share	268.0	270.3	269.9	267.5	270.7
Dividends declared per share	$0.340	$0.340	$0.295	$0.250	$0.240
Other Data					
Tons sold	248.5	249.4	243.1	239.7	250.6
Net cash provided by (used in) continuing operations:					
Operating activities	$1,599.8	$1,652.1	$1,104.5	$1,038.6	$1,316.5
Investing activities	(1,070.1)	(3,737.2)	(692.7)	(404.2)	(409.1)
Financing activities	(663.3)	1,678.5	(77.1)	(104.6)	(498.0)
Adjusted EBITDA	1,836.5	2,122.6	1,826.5	1,291.2	1,727.7
Adjusted Income from Continuing Operations	238.7	1,011.9	872.9	543.0	847.1
Adjusted Diluted EPS	$0.84	$3.77	$3.10	$1.96	$3.09
Balance Sheet Data (at period end)					
Total assets	$15,809.0	$16,733.0	$11,363.1	$9,955.3	$9,695.6
Total long-term debt (including capital leases)	6,252.9	6,657.5	2,750.0	2,752.3	2,793.6
Total stockholders' equity	4,938.8	5,515.8	4,689.3	3,755.9	3,119.5

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Adjusted EBITDA is calculated as follows:

	Year Ended December 31,				
	2012	2011	2010	2009	2008
		(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$825.0	$446.0	$912.3
Depreciation, depletion and amortization	663.4	474.3	429.5	390.8	387.2
Asset retirement obligation expenses	67.0	52.6	45.9	38.9	47.2
Asset impairment and mine closure costs	929.0	—	—	34.7	—
Amortization of basis difference related to equity affiliates	4.6	—	—	—	—
Interest expense, net	381.1	219.7	212.4	193.0	217.1
Income tax provision	262.3	363.2	313.7	187.8	163.9
Adjusted EBITDA	$1,836.5	$2,122.6	$1,826.5	$1,291.2	$1,727.7

Adjusted Income from Continuing Operations is calculated as follows:

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(Dollars in millions)				
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$825.0	$446.0	$912.3
Asset impairment and mine closure costs	929.0	—	—	34.7	—
Income tax benefit related to asset impairment and mine closure costs	(227.3)	—	—	(12.1)	—
Remeasurement expense (benefit) related to foreign income tax accounts	7.9	(0.9)	47.9	74.4	(65.2)
Adjusted Income from Continuing Operations	$238.7	$1,011.9	$872.9	$543.0	$847.1

Adjusted Diluted EPS is calculated as follows:

	Year Ended December 31,				
	2012	2011	2010	2009	2008
(Loss) income from continuing operations	$(1.80)	$3.77	$2.92	$1.60	$3.33
Asset impairment and mine closure costs, net of income taxes	2.61	—	—	0.08	—
Remeasurement expense (benefit) related to foreign income tax accounts	0.03	—	0.18	0.28	(0.24)
Adjusted Diluted EPS	$0.84	$3.77	$3.10	$1.96	$3.09

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 28 active coal mining operations located in the United States (U.S.) and Australia. We have a majority interest in 27 of those coal operations and a 50% equity interest in the Middlemount Mine in Australia. We also own a noncontrolling interest in a mining operation in Venezuela. In addition to our mining operations, we market and broker coal from other coal producers, both as principal and agent, and trade coal and freight-related contracts through trading and business offices in China, Australia, the United Kingdom, Germany, Singapore, India, Indonesia and the U.S.

In 2012, we produced and sold 225.7 million and 248.5 million tons of coal, respectively, from continuing operations. During that period, approximately 89% of our worldwide sales (by volume) were under long-term contracts. For the year ended December 31, 2012, 75% of our total sales (by volume) were to U.S. electricity generators, 23% were to customers outside the U.S. and 2% were to the U.S. industrial sector.

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We conduct business through four principal operating segments: Western U.S. Mining, Midwestern U.S. Mining, Australian Mining and Trading and Brokerage. Our Western U.S. Mining segment consists of our Powder River Basin, Southwest and Colorado operations, while our Midwestern U.S. Mining segment consists of our operations in Illinois and Indiana.

The principal business of the Western and Midwestern U.S. Mining segments is the mining, preparation and sale of thermal coal. In the U.S., we typically supply thermal coal to domestic electricity generators and industrial customers for power generation under long-term contracts, with a portion sold into seaborne export markets.

The business of our Australian Mining segment is the mining of various qualities of metallurgical coal, as well as thermal coal. Our Australian Mining segment 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. Revenues from individual countries generally vary year by year based on demand for electricity and steel, global economic conditions and several other factors, including those specific to each country. Industry commercial practice, and our practice, is to negotiate pricing for metallurgical and seaborne thermal coal contracts on a quarterly and annual basis, respectively. On October 26, 2011, we acquired Macarthur Coal Limited (PEA-PCI), making us the third-largest holder of Australian coal reserves. From the date of acquisition, PEA-PCI's results from operations have been included in our results and reflected in our Australian Mining segment, except for the activity associated with certain equity affiliates, which is reflected in our Corporate and Other segment.

The principal business of our Trading and Brokerage segment is the marketing and brokering of coal for other producers, both as principal and agent, and the trading of coal and freight-related contracts. The segment also provides transportation-related services in support of our coal trading strategy and conducts hedging activities in support of sales from our mining operations.

Our fifth segment, Corporate and Other, includes mining and export/transportation joint ventures and activities associated with certain energy-related commercial matters, Btu Conversion, the optimization of our coal reserve and real estate holdings and the closure of inactive mining sites.

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 (CTG) or transportation fuels (CTL) and advancing clean coal technologies, including carbon capture and storage (CCS).

As discussed more fully in Part I, 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, competition from other fuel sources 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.

Results of Operations

Non-U.S. GAAP Financial Measures

The following discussion of our results of operations includes references to and analysis of Adjusted EBITDA, Adjusted Income from Continuing Operations and Adjusted Diluted EPS, which are financial measures not recognized in accordance with U.S. generally accepted accounting principles (GAAP). These financial measures are not intended to serve as alternatives to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies. Beginning with this report, we have modified the definitions of these non-GAAP financial measures to also exclude the impact of asset impairment and mine closure costs because we believe that excluding these impacts is useful in comparing our 2012 results with those of prior and future periods.

Adjusted EBITDA is defined as income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization, asset impairment and mine closure costs and amortization of basis difference associated with equity method investments. Adjusted EBITDA is used by management to measure our segments' operating performance and we believe it is a useful indicator of our ability to meet debt service and capital expenditure requirements.

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Adjusted Income from Continuing Operations and Adjusted Diluted EPS are defined as income from continuing operations and diluted earnings per share from continuing operations (EPS), respectively, excluding the impacts of asset impairment and mine closure costs, net of tax, and the remeasurement of foreign income tax accounts on our income tax provision. The income tax benefits related to asset impairment and mine closure costs have been calculated based on the enacted tax rate in the jurisdiction in which they have been or will be realized, adjusted for the estimated recoverability of those benefits. We have included Adjusted Income from Continuing Operations and Adjusted Diluted EPS in our discussion because, in the opinion of management, excluding those foregoing items is useful in comparing our current results with those of prior periods. We also believe that excluding the impact of the remeasurement of our foreign income tax accounts represents a meaningful indicator of our ongoing effective tax rate.
A reconciliation of Adjusted EBITDA to its most comparable measure under U.S. GAAP is included in Note 26. "Segment and Geographic Information" of the consolidated financial statements. Adjusted Income from Continuing Operations and Adjusted Diluted EPS are reconciled to their most comparable measures under U.S. GAAP in the sections that follow.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Summary

Global coal markets reflected a challenged environment during the year ended December 31, 2012, characterized by year-over-year declines in coal use in the U.S. and weak international pricing.

Coal's share of U.S. electricity generation for all sectors declined from 42.3% in 2011 to 37.6% in 2012 according to the U.S. Energy Information Administration's (EIA) January 2013 "Short-Term Energy Outlook," with a majority of that loss having occurred during the first half of the year. A substantial portion of that lost share was assumed by natural gas due to a year-over-year decline in full year average U.S. natural gas prices of 31% during that same period. U.S. coal consumption was further hindered in 2012 by a year-over-year decline in heating-degree days due to mild winter weather experienced in the first and fourth quarter of that year and weak economic activity. We were not immune to these market conditions. In addition to initiating planned year-over-year reductions in our coal production in the U.S., we permanently ceased production at our Air Quality Mine in Indiana in September 2012 due to uneconomic market conditions for the type of coal previously produced at that site. We also announced the permanent closure of our Willow Lake Mine in Illinois in November 2012 due to a continued failure by that site to meet standards for safety, compliance and operating performance we deem acceptable. Reflecting this challenged domestic environment, we sold 10.1 million fewer tons of coal from our Western and Midwestern U.S. Mining segments in 2012 compared with the prior year.

Steel production in the major Asian economies grew by approximately 3% in 2012 compared to the prior year according to data recently published by the World Steel Association (WSA), a modest rate compared with that observed during 2011. During that same period, worldwide steel production grew by 1%, with growth in Asia and the U.S. offset by reduced production in Europe due to an economic slowdown in that region. That softness in international steel markets led to a decline in settled prices for seaborne metallurgical coal as 2012 progressed, with spot prices rebounding from lows seen in September.

International thermal coal markets continued to grow in 2012 compared to the prior year, led by imports into China, India, Japan and Europe. Nonetheless, year-over-year increases in seaborne thermal coal supply outpaced that increase in demand in 2012, which led to a decline in index prices from the prior year for thermal coal originating from Newcastle, Australia.

In spite of a modest year-over-year revenue increase of 2.3%, our Segment Adjusted EBITDA decreased by 9.4% compared to 2011 led by reductions in realized seaborne coal pricing ($432.7 million, net of sales-related costs), and lower U.S. volumes, partially offset by higher volumes from our Australian platform due to the prior year acquisition of PEA-PCI and the benefits of mine expansions and higher contract pricing in the U.S.

(Loss) income from continuing operations, net of income taxes, changed unfavorably by $1,483.7 million in 2012 compared to the prior year due to lower Segment and Corporate and Other Adjusted EBITDA, increases in interest expense and depreciation, depletion and amortization resulting from the PEA-PCI acquisition and $929.0 million in charges related to asset impairments and mine closures. Year-over-year changes in our effective tax rate further reduced earnings in 2012 compared to 2011 due mainly to an increase in our valuation allowance against Australian loss carryforwards. Adjusted Income from Continuing Operations, which excludes the impacts of asset impairment and mine closure costs, net of tax, and the remeasurement of foreign income tax accounts, also decreased in 2012 compared to the prior year, though by a lesser amount of $773.2 million, or 76.4%.

Net (loss) income also decreased on a year-over-year basis in 2012 due to lower results from continuing operations and charges recognized in 2012 related to the closing of our Air Quality Mine, which is classified as a discontinued operation as of December 31, 2012.

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We ended 2012 with total available liquidity of approximately $2.2 billion, which was relatively in line with our ending liquidity of $2.3 billion in 2011. Refer to the "Liquidity and Capital Resources" section contained within this Item 7 for further discussion of factors affecting our available liquidity.

Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Tons Sold	
	2012	2011	Tons	%
	(Tons in millions)			
Australian Mining	33.0	25.3	7.7	30.4 %
Western U.S. Mining	165.2	173.6	(8.4)	(4.8)%
Midwestern U.S. Mining	27.4	29.1	(1.7)	(5.8)%
Trading and Brokerage	22.9	21.4	1.5	7.0 %
Total tons sold	248.5	249.4	(0.9)	(0.4)%

Revenues

The following table presents revenues by operating segment for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2012	2011	$	%
	(Dollars in millions)			
Australian Mining	$3,503.6	$3,080.7	$422.9	13.7 %
Western U.S. Mining	2,949.3	2,900.4	48.9	1.7 %
Midwestern U.S. Mining	1,403.7	1,402.6	1.1	0.1 %
Trading and Brokerage	199.9	475.1	(275.2)	(57.9)%
Corporate and Other	21.0	37.1	(16.1)	(43.4)%
Total revenues	$8,077.5	$7,895.9	$181.6	2.3 %

Revenues from our Australian Mining segment increased in 2012 compared to the prior year due to the benefit of additional sales volumes ($910.3 million), which were driven by incremental year-over-year volume contributions from PEA-PCI mines acquired in the fourth quarter of 2011 ($508.8 million) and an overall production increase in our legacy Australian platform ($401.5 million). The year-over-year increase in our legacy platform production in 2012 resulted from the benefit of completed mine expansions at our Wilpinjong and Millennium mines, lower overall downtimes due to longwall moves and the adverse production effects experienced in the second half of 2011 due to a roof fall during the third quarter of that year, partially offset by production challenges from certain of our contractor-operated mines. The favorable volume variance in 2012 compared to 2011 was partially offset by an unfavorable price variance between those periods due to the impact of lower year-over-year average seaborne coal prices discussed above ($487.4 million). Metallurgical coal sales totaled 14.1 million and 9.3 million tons in 2012 and 2011, respectively, with the year-over-year increase largely attributable to incremental volumes contributed by PEA-PCI.

Revenues from our Western U.S. Mining segment increased during 2012 compared to the prior year resulting mainly from higher contract pricing ($167.9 million). That favorable price variance was partially offset by the unfavorable net impact of sales volume and mix ($119.0 million). Demand from electric power generators served by this segment was adversely affected in 2012 compared to the prior year by competition from natural gas and a decrease in heating-degree days from mild winter weather. Those effects were only partially offset by a slight increase in heating-degree days in 2012 compared to 2011 due to warm summer weather.

Midwestern U.S. Mining segment revenues were relatively unchanged in 2012 compared to the prior year. Revenues from that segment benefited from higher contract prices in 2012 compared to 2011 ($70.6 million), the effect of which was almost entirely offset by the unfavorable net impact of sales volume and mix in 2012 versus the prior year ($69.5 million) due to soft U.S. coal market demand.

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The decline in our Trading and Brokerage segment revenues during 2012 compared to 2011 was mainly driven by a comparatively higher portion of our contract revenue being recognized on a net basis in the current period due to the expiration of certain physical delivery contracts that were recognized on a gross basis in the year-ago period ($180.3 million). Revenues from that segment were also affected in 2012 compared to the prior year by lower realized prices on physical shipments and counterparty nonperformance under certain contracts.

The decrease in our Corporate and Other segment revenues for the year ended December 31, 2012 compared to the prior year mainly resulted from our receipt of a $14.6 million project development fee associated with our involvement in the Prairie State Energy Campus (Prairie State) in the second quarter of 2011.

Segment Adjusted EBITDA

The following table presents Segment Adjusted EBITDA for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2012	2011	$	%
	(Dollars in millions)			
Australian Mining	$938.9	$1,194.3	$(255.4)	(21.4)%
Western U.S. Mining	832.8	766.0	66.8	8.7%
Midwestern U.S. Mining	427.0	402.9	24.1	6.0%
Trading and Brokerage	119.7	197.0	(77.3)	(39.2)%
Total Segment Adjusted EBITDA	$2,318.4	$2,560.2	$(241.8)	(9.4)%

Adjusted EBITDA from our Australian Mining segment was adversely affected during the year ended December 31, 2012 compared to the prior year by lower seaborne coal pricing, net of sales-related costs ($432.7 million), cost increases and production performance and geological challenges encountered at certain of our contractor-operated mines ($92.6 million), inflationary cost escalations ($76.8 million), the foreign currency impact on operating costs and the remeasurement of monetary balance sheet items, net of hedging ($26.5 million) and the effect of the Australian government's carbon pricing framework implemented in July 2012, net of transition benefits received ($12.4 million). Those factors were partially offset in 2012 compared to 2011 by lower year-over-year costs associated with longwall moves and the roof fall experienced in the third quarter of the prior year ($206.9 million) and the benefit of higher sales volumes ($174.8 million), which were due to the inclusion of PEA-PCI results on a full year basis in 2012 and the effect of mine expansions in our legacy Australian platform.

Higher contract pricing, net of sales-related costs, drove an increase in Western U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2012 compared to the prior year ($135.6 million). Adjusted EBITDA results for 2012 also rose year-over-year from the impacts of a provision for a litigation settlement ($24.5 million) and expenditures associated with certain geologic events encountered at our Twentymile Mine ($17.1 million) in 2011. Those benefits were partially offset during the year ended December 31, 2012 compared to 2011 by an unfavorable net volume and mix variance ($87.1 million) and the effect of higher costs and usage of labor and materials and services ($31.3 million), the latter of which includes costs associated with planned longwall moves that occurred during the period.

Midwestern U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2012 benefited from higher contract pricing, net of sales-related costs, compared to the prior year ($60.0 million) and the absence of costs incurred in response to heavy rains experienced in the Midwest region during 2011 ($12.2 million). These benefits were partially offset by higher costs incurred during 2012 compared to the prior year associated with overburden removal ($18.2 million) and labor wages and benefits ($13.8 million). The net impact of changes in sales volume and mix during 2012 compared to 2011 was immaterial, with the decrease in shipped volumes offset by the effect of the expiration of a low-margin purchased coal contract in 2011.

Trading and Brokerage segment Adjusted EBITDA for the year ended December 31, 2012 decreased compared to the prior year due to lower realized price margins on U.S. and Australian export volumes ($63.1 million). Adjusted EBITDA results for the segment were also adversely affected in 2012 compared to the prior year by a loss recognized in the third quarter of 2012 associated with the discounted sale to a third party of our then-outstanding claim with the special administrators of MF Global UK Limited ($4.1 million).

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(Loss) Income From Continuing Operations Before Income Taxes

The following table presents (loss) income from continuing operations before income taxes for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Income	
	2012	2011	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$2,318.4	$2,560.2	$(241.8)	(9.4)%
Corporate and Other Adjusted EBITDA[1]	(481.9)	(437.6)	(44.3)	10.1%
Depreciation, depletion and amortization	(663.4)	(474.3)	(189.1)	39.9%
Asset retirement obligation expenses	(67.0)	(52.6)	(14.4)	27.4%
Asset impairment and mine closure costs	(929.0)	—	(929.0)	n.m.
Amortization of basis difference related to equity affiliates	(4.6)	—	(4.6)	n.m.
Interest expense	(405.6)	(238.6)	(167.0)	70.0%
Interest income	24.5	18.9	5.6	29.6%
(Loss) income from continuing operations before income taxes	$(208.6)	$1,376.0	$(1,584.6)	(115.2)%

(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.

(Loss) income from continuing operations before income taxes for the year ended December 31, 2012 changed unfavorably compared to the prior year. In addition to the decrease in Segment Adjusted EBITDA discussed above, our results were negatively affected compared to 2011 by lower Corporate and Other Adjusted EBITDA, increased depreciation, depletion and amortization and higher expenses associated with asset retirement obligations, asset impairments and mine closures and interest. These factors were partially offset by higher interest income recognized in 2012 compared to 2011.

Corporate and Other Adjusted EBITDA was adversely impacted in 2012 by higher losses associated with our 50% interest in the newly operational Middlemount Mine acquired as part of the PEA-PCI acquisition compared to the prior year ($41.4 million), which were affected in the current year by unfavorable pricing in the international metallurgical coal market and contractor mining issues. Corporate and Other Adjusted EBITDA also declined during 2012 compared to the prior year as a result of gains recognized in 2011 related to 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 sales of non-strategic coal reserves in Kentucky ($31.7 million) executed during that period, in addition to our prior year receipt of a project development fee related to our involvement in Prairie State ($14.6 million). The effect of those factors was partially offset by the impact of costs incurred during 2011 related to the acquisition of PEA-PCI ($85.2 million) that did not recur in the current year.

Depreciation, depletion and amortization expenses increased during 2012 compared to the prior year due to incremental expenses associated with PEA-PCI mines acquired in the fourth quarter of 2011 ($108.3 million) and higher expenses from our legacy Australian mining platform caused by increased depletion rates and higher overall production ($54.1 million).

Asset retirement obligation expenses were higher in 2012 compared to 2011. The increase was largely attributable to incremental expense associated with acquired PEA-PCI mines and the impact of reclamation plan changes at certain of our U.S. mines.

We recognized $929.0 million in aggregate asset impairment and mine closure charges during 2012, which contributed significantly to the unfavorable year-over-year decrease in earnings observed in the current period. Refer to Note 3. "Asset Impairment and Mine Closure Costs" to the accompanying consolidated financial statements, which is incorporated herein by reference, for further information regarding the nature and composition of the charges.

Additional debt incurred in connection with the PEA-PCI acquisition resulted in higher interest expense during 2012 compared to the prior year. The impact of those expenses was partially offset by the effect of interest expense associated with bridge financing obtained during the prior year in support of that acquisition.

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Interest income increased in 2012 compared to the prior year due to income from interest-bearing receivables we hold associated with our loans to the Middlemount Mine joint venture. This incremental income was partially offset in the current year compared to the prior year by the impact of lower cash and cash equivalents balances and a decrease in investments in debt securities associated with our pro-rata funding of the Newcastle Coal Infrastructure Group. Our remaining holdings of those debt securities were sold during 2012.

(Loss) Income from Continuing Operations, Net of Income Taxes

The following table presents (loss) income from continuing operations, net of income taxes, for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Income	
	2012	2011	$	%
	(Dollars in millions)			
(Loss) income from continuing operations before income taxes	$(208.6)	$1,376.0	$(1,584.6)	(115.2)%
Income tax provision	262.3	363.2	100.9	27.8%
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$(1,483.7)	(146.5)%

(Loss) income from continuing operations, net of income taxes, changed unfavorably in 2012 compared to 2011 due to adverse changes in before-tax earnings discussed above, partially offset by a lower income tax provision.

Our 2012 income tax provision benefited from the following factors compared to 2011:

- The impact of lower current year earnings, including the net tax benefit associated with asset impairment and mine closure costs ($456.8 million); and
- The recognition of a net tax benefit in 2012 due to the restructuring of foreign operations ($74.7 million), comprised of a realized U.S. capital loss benefit, net of valuation allowance, and a foreign tax benefit due to the tax basis reset required upon the PEA-PCI operations joining our Australian consolidated tax group.

The impact of those benefits was partially offset by the following adverse factors affecting our 2012 income tax provision and effective tax rate compared to the prior year:

- An increase in our valuation allowance against Australian loss carryforwards recognized during 2012 based on changes in the estimated future realization of those carryforwards, the assessment of which was affected by a loss utilization factor on Australian net operating losses which we expect will limit recoverability ($332.2 million);
- A net deferred tax liability recognized in connection with the Australian minerals resource rent tax (MRRT), which was implemented in 2012 ($77.2 million); and
- The impact from the remeasurement of non-U.S. tax accounts as a result of the current year strengthening of the Australian dollar compared with weakening in the prior year ($8.8 million), as set forth in the table below.

	December 31,			Rate Change	
	2012	2011	2010	2012	2011
Australian dollar to U.S. dollar exchange rate	$1.0384	$1.0156	$1.0163	$0.0228	$(0.0007)

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Adjusted Income From Continuing Operations

The following table presents Adjusted Income from Continuing Operations for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Income	
	2012	2011	$	%
	(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$(1,483.7)	(146.5)%
Asset impairment and mine closure costs	929.0	—	929.0	n.m.
Income tax benefit related to asset impairment and mine closure costs	(227.3)	—	(227.3)	n.m.
Remeasurement expense (benefit) related to foreign income tax accounts	7.9	(0.9)	8.8	(977.8)%
Adjusted Income from Continuing Operations	$238.7	$1,011.9	$(773.2)	(76.4)%

Adjusted Income from Continuing Operations decreased in 2012 compared to 2011 due to unfavorable year-over-year changes in Segment and Corporate and Other Adjusted EBITDA, higher expenses related to depreciation, depletion and amortization, asset retirement obligations and interest, partially offset by higher interest income and a lower income tax provision recognized in 2012 compared to 2011, as discussed above.

Net (Loss) Income Attributable to Common Stockholders

The following table presents net (loss) income attributable to common stockholders for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Income	
	2012	2011	$	%
	(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$(1,483.7)	(146.5)%
Loss from discontinued operations, net of income taxes	(104.2)	(66.5)	(37.7)	56.7 %
Net (loss) income	(575.1)	946.3	(1,521.4)	(160.8)%
Net income (loss) attributable to noncontrolling interests	10.6	(11.4)	(22.0)	193.0 %
Net (loss) income attributable to common stockholders	$(585.7)	$957.7	$(1,543.4)	(161.2)%

Net (loss) income attributable to common stockholders decreased in 2012 compared to the prior year largely due to the adverse changes in (loss) income from continuing operations, net of income taxes, discussed above, and the unfavorable impact of current year results from discontinued operations and losses allocated to noncontrolling interests in the prior year.

Loss from discontinued operations, net of income taxes, for 2012 was negatively affected by aggregate after-tax charges of $75.0 million, which included an after-tax impairment charge of $68.8 million, recognized in that period related to the shutdown of our Air Quality Mine due to uneconomic market conditions for the type of coal previously produced at that site. The effect of those charges was partially offset by improved results during 2012 compared to the prior year from our held for sale Wilkie Creek Mine, which was adversely impacted by flooding in 2011.

The effect of allocating net income (loss) to noncontrolling interests was unfavorable on a year-over-year basis in 2012. This adverse change was driven by the impact of the allocation of losses related to ArcelorMittal Mining Australia B.V.'s interest in PEA-PCI from the acquisition and control date of October 26, 2011 to the date we acquired that noncontrolling interest on December 21, 2011.

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Diluted EPS

The following table presents diluted EPS for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2012	2011	$	%
Diluted EPS attributable to common stockholders:				
(Loss) income from continuing operations	$(1.80)	$3.77	$(5.57)	(147.7)%
Loss from discontinued operations	(0.39)	(0.25)	(0.14)	56.0%
Net (loss) income	$(2.19)	$3.52	$(5.71)	(162.2)%

Diluted EPS decreased in 2012 compared to 2011 commensurate with the decline in results from continuing and discontinued operations between those periods. Diluted EPS was also modestly affected in 2012 compared to 2011 by a lower share base (2.3 million shares). The decreased share base was driven by lower weighted average basic shares outstanding (1.1 million shares) due to the effect of current year share repurchases, as partially offset by the vesting of stock granted to employees, and the exclusion of the impact of dilutive securities from weighted average diluted shares outstanding in 2012 due to a net loss recognized in the current year, whereas such impact was included in 2011 (1.2 million shares).

Adjusted Diluted EPS

The following table presents Adjusted Diluted EPS for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2012	2011	$	%
Adjusted Diluted EPS Reconciliation:				
(Loss) income from continuing operations	$(1.80)	$3.77	$(5.57)	(147.7)%
Asset impairment and mine closure costs, net of income taxes	2.61	—	2.61	n/a
Remeasurement expense (benefit) related to foreign income tax accounts	0.03	—	0.03	n/a
Adjusted Diluted EPS	$0.84	$3.77	$(2.93)	(77.7)%

Adjusted Diluted EPS decreased in 2012 compared to 2011 commensurate with the decline in Adjusted Income from Continuing Operations during that period. Similar to Diluted EPS, Adjusted Diluted EPS was also modestly affected in 2012 compared to 2011 by a lower share base, as discussed above.

Other

The net fair value of our foreign currency cash flow hedges decreased from a net asset of $490.6 million at December 31, 2011 to a net asset of $286.9 million at December 31, 2012 primarily due to the monetization of certain Australian dollar forward contracts in exchange for aggregate realized cash proceeds of $151.8 million, which were comprised of an aggregate notional amount of $1.9 billion Australian dollars originally contracted for settlement during 2014 and 2015 prior to contract termination, in the fourth quarter of 2012 and the ongoing realization of hedge gains in 2012. This decrease is reflected in “Other current assets” and “Investments and other assets” in the consolidated balance sheets.

The fair value of our coal trading positions designated as cash flow hedges of future sales, before the application of counterparty cash margin, increased from a net asset of $22.4 million at December 31, 2011 to $153.1 million at December 31, 2012 due to favorable market price movements on those positions.

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.

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

Our 2011 revenues increased compared to the prior year by $1,227.7 million and Segment Adjusted EBITDA increased over the prior year by $379.0 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 in 2011 compared to the prior year by $187.8 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 2011 with total available liquidity of $2.3 billion.

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) to Tons Sold		
	2011	2010	Tons	%	
	(Tons in millions)				
Australian Mining	25.3	25.3	—	—	%
Western U.S. Mining	173.6	163.8	9.8	6.0	%
Midwestern U.S. Mining	29.1	28.6	0.5	1.7	%
Trading and Brokerage	21.4	25.4	(4.0)	(15.7	)%
Total tons sold	249.4	243.1	6.3	2.6	%

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)				
Australian Mining	$3,080.7	$2,399.9	$680.8	28.4	%
Western U.S. Mining	2,900.4	2,706.3	194.1	7.2	%
Midwestern U.S. Mining	1,402.6	1,248.9	153.7	12.3	%
Trading and Brokerage	475.1	291.1	184.0	63.2	%
Corporate and Other	37.1	22.0	15.1	68.6	%
Total revenues	$7,895.9	$6,668.2	$1,227.7	18.4	%

The increase in Australian Mining segment revenues in 2011 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, PEA-PCI 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 segment revenues were higher in 2011 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.

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Trading and Brokerage segment revenues were higher in 2011 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 in 2011 compared to the prior year were due to a higher weighted average sales price of 10.4% driven by favorable contract pricing. Volumes were also higher (1.7%) 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)			
Australian Mining	$1,194.3	$977.4	$216.9	22.2 %
Western U.S. Mining	766.0	816.7	(50.7)	(6.2)%
Midwestern U.S. Mining	402.9	309.9	93.0	30.0 %
Trading and Brokerage	197.0	77.2	119.8	155.2 %
Total Segment Adjusted EBITDA	$2,560.2	$2,181.2	$379.0	17.4 %

Australian Mining segment Adjusted EBITDA increased in 2011 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 2011 roof fall and resulting 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.

Western U.S. Mining segment Adjusted EBITDA decreased in 2011 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.

Midwestern U.S. Mining operations’ Adjusted EBITDA increased compared to the prior year due to a higher weighted average sales price (10.4%), 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.

Trading and Brokerage segment Adjusted EBITDA increased in 2011 compared to 2010 primarily due to higher margins on our brokerage activity due to higher prices as discussed above.

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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	$2,560.2	$2,181.2	$379.0	17.4 %
Corporate and Other Adjusted EBITDA[1]	(437.6)	(354.7)	(82.9)	23.4 %
Depreciation, depletion and amortization	(474.3)	(429.5)	(44.8)	10.4 %
Asset retirement obligation expense	(52.6)	(45.9)	(6.7)	14.6 %
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	$1,376.0	$1,138.7	$237.3	20.8 %

(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 greater in 2011 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 in 2011 compared to the prior year due primarily to the following:

- Higher 2011 expenses in support of our international expansion, acquisition activity and other growth initiatives, including $85.2 million of expenses associated with the acquisition of PEA-PCI; and
- Lower results from equity affiliates ($17.5 million) in 2011 compared to the prior year due to losses recognized in 2011 associated with our joint venture arrangement in Australia ($7.3 million) and earnings recognized in 2010 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 2011 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 2011 gains of $31.7 million associated with sales of non-strategic coal reserves in Kentucky and Illinois, partially offset by 2010 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
- A gain recorded in 2011 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 in 2011 compared to the prior year primarily driven by additional expense associated with the assets acquired in the PEA-PCI acquisition.

Interest expense increased $16.6 million in 2011 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 2010 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.

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Income from Continuing Operations, Net of Income Taxes

The following table presents income from continuing operations, net of income taxes, 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	$1,376.0	$1,138.7	$237.3	20.8 %
Income tax provision	363.2	313.7	(49.5)	(15.8)%
Income from continuing operations, net of income taxes	$1,012.8	$825.0	$187.8	22.8 %

The provision for income taxes increased in 2011 compared to the prior year due to 2011 earnings ($81.1 million), a change in valuation allowances ($44.1 million) related primarily to alternative minimum tax credits released in 2010 and higher 2011 state income taxes ($17.1 million). The increases to income tax expense were partially offset by lower year-over-year foreign earnings repatriation expense ($76.9 million) in 2011 and a 2011 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 2010 as the Australian exchange rate decreased against the U.S. dollar in the current year as compared to an increase in 2010, 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

Adjusted Income From Continuing Operations

The following table presents Adjusted Income from Continuing Operations for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Income	
	2011	2010	$	%
	(Dollars in millions)			
Income from continuing operations, net of income taxes	$1,012.8	$825.0	$187.8	22.8 %
Remeasurement (benefit) expense related to foreign income tax accounts	(0.9)	47.9	(48.8)	(101.9)%
Adjusted Income from Continuing Operations	$1,011.9	$872.9	$139.0	15.9 %

Adjusted Income from Continuing Operations increased in 2011 compared to the prior year due to the higher Total Segment Adjusted EBITDA, partially offset by lower Corporate and Other Adjusted EBITDA and increased expenses associated with depreciation, depletion and amortization, interest and income taxes.

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, net of income taxes	$1,012.8	$825.0	$187.8	22.8 %
Loss income from discontinued operations, net of income taxes	(66.5)	(22.8)	(43.7)	191.7 %
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 %

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Net income attributable to common stockholders increased in 2011 compared to the prior year due to the increase in income from continuing operations, net of income taxes, as discussed above.
Loss from discontinued operations for 2011 reflects a loss of $66.5 million as compared to a loss of $22.8 million in 2010 due primarily to higher year-over-year losses in 2011 associated with our held for sale Wilkie Creek Mine.
Net (loss) income attributable to noncontrolling interests in 2011 was driven by ArcelorMittal Mining Australasia B.V.'s interest in PEA-PCI from the acquisition and control date of October 26, 2011 to the date we acquired ArcelorMittal Mining Australasia B.V. on December 21, 2011.
Diluted EPS
The following table presents diluted EPS for the years ended December 31, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2011	2010	$	%
Diluted EPS attributable to common stockholders:				
Income from continuing operations	$3.77	$2.92	$0.85	29.1 %
Loss from discontinued operations	(0.25)	(0.08)	(0.17)	212.5 %
Net income	$3.52	$2.84	$0.68	23.9 %

Diluted EPS increased in 2011 compared to 2010 commensurate with the increase in results from continuing operations between those periods, partially offset by higher losses in 2011 from discontinued operations, as discussed above.
Adjusted Diluted EPS
The following table presents Adjusted Diluted EPS for the years ended December 31, 2011 and 2010:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2011	2010	$	%
Adjusted Diluted EPS Reconciliation:				
Income from continuing operations	$3.77	$2.92	$0.85	29.1 %
Remeasurement (benefit) expense related to foreign income tax accounts	—	0.18	(0.18)	(100.0)%
Adjusted Diluted EPS	$3.77	$3.10	$0.67	21.6 %

Adjusted Diluted EPS increased in 2011 compared to 2010 commensurate with the increase in Adjusted Income from Continuing Operations, as discussed above.
Outlook
Our near-term outlook is intended to coincide with the next 12 to 24 months, with subsequent periods addressed in our long-term outlook.
Near-Term Outlook
Near-term coal markets continue to reflect a challenging environment. While global coal prices have risen from lows in 2012, prices remain constrained. A number of producers have announced production cuts and reduced planned capital investments as a result. Domestically, low U.S. natural gas prices led to a significant year-over-year decline in U.S. coal demand in 2012. Although natural gas prices have risen above 2012 levels, elevated utility inventories continue to impact coal prices. Significant U.S. coal production cuts occurred in 2012, and we expect 2013 coal production to be even lower, with a majority of those further cuts expected in regions outside of those in which we operate.
Overall, the World Bank estimates that global economic growth in 2012, as measured by global gross domestic product (GDP) growth, slowed compared to the prior year, muting growth of both global electricity generation and steel production. Supply-demand fundamentals have strengthened recently in the Asia-Pacific region, while Atlantic regions continue to lag.

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According to China Customs, China's metallurgical and thermal net coal imports, which support steel production, electricity generation and other industrial sectors, increased a combined 34% over the prior year to an aggregate 280 million tonnes in 2012. China's December 2012 imports reached a monthly record 35 million tonnes as the country began to experience its coldest winter in decades. China coal-fueled electricity generation in 2012 was in line with the prior year, according to the China Electricity Council. According to the India Central Electricity Authority, Indian coal-fueled electricity generation increased 13% in 2012 compared to 2011. India's coal import growth continued in 2012 led by a 23% rise in thermal coal imports. Japan increased coal-fueled electricity generation in 2012 compared to the prior year due to high seaborne natural gas prices and reduced nuclear generation. European hard coal-fueled electricity generation rose 18% in 2012 compared to 2011.

In spite of the year-over-year growth in international thermal coal demand in 2012, increases in seaborne supply for thermal coal still outpaced increased demand during that period, which led to a decline in index prices in 2012 from the prior year for thermal coal originating from Newcastle, Australia. We are targeting our 2013 Australian thermal exports at 11 to 12 million tons.

Turning to steel production and related metallurgical coal demand, WSA reported that steel production in China increased approximately 3% in 2012 compared with 2011, as China accelerated steel production in the fourth quarter of 2012 by 9% compared to the corresponding prior year period. According to the WSA, year-over-year steel production grew by 1% on a worldwide basis in 2012, with growth in Asia and the U.S. offset by reduced production from Europe and South America.

In January 2013, the World Bank lowered global economic activity estimates for 2013 and 2014. The World Bank estimates global economic activity, as measured by global GDP, will grow 2.4% in 2013 and 3.1% in 2014, led by China, India and Indonesia. China's GDP is projected to grow 8.4% and 8.0% in 2013 and 2014, respectively. India's GDP is projected to grow 6.1% and 6.8% in 2013 and 2014, respectively, while Indonesia's GDP is expected to grow 6.3% and 6.6% in 2013 and 2014, respectively. According to the WSA October 2012 Short Range Outlook, global steel use is expected to increase 3.2% in 2013, with China steel use expected to grow by 3.1%. Both of these estimates reflect a downward revision of projections released by the WSA in April of 2012.

Softness in international steel markets led to lower settled prices for metallurgical coal as 2012 progressed. Metallurgical coal prices for high quality hard coking coal and low volatile pulverized coal injections settled at approximately $165 and $124 per tonne, respectively, for quarterly contracts commencing January 2013. We settled new contracts for first quarter 2013 metallurgical coal shipments largely in line with these recent settlements, as adjusted for quality differentials on delivered coal. We are targeting total 2013 metallurgical coal sales of approximately 15 to 16 million tons. Our total Australia coal production for 2013 is targeted at 33 to 36 million tons. We expect an increase in our Australian operating costs in 2013 compared to 2012 due to transition costs associated with the completion of our conversion to owner-operator status at certain of our Australian mines, the timing of overburden removal at certain of our mines, a higher mix of metallurgical coal production, which consists of higher production costs compared to our thermal coal production in that region, and the full year effect of Australia's carbon pricing framework and new royalty rates in Queensland.

In the U.S., the EIA in its February 2013 Short-Term Energy Outlook projects U.S. electricity generation from coal to increase in 2013 while electricity generation from natural gas is expected to decline from 2012 levels. The EIA projects the price of natural gas to increase by 28% in 2013 compared to 2012 to an average of $3.53 per MMBtu, resulting in an 8% decline in electricity generation from natural gas. Consequently, the EIA also projects electricity generation from coal will rebound modestly in 2013 and increase by 4% over 2012, while still falling short of levels realized in 2011.

We are targeting our 2013 U.S. volumes at 180 to 190 million tons with 90% to 95% of those volumes committed and priced. As of January 29, 2013, we had 50% to 60% of 2014 volumes priced based on projected 2013 production levels. We anticipate that average realized pricing from our U.S. mining operations will decrease between a range of 5% and 10% on a per-ton basis in 2013 compared to 2012 due to new U.S. coal supply agreements and price reopener provisions in certain of our existing U.S. coal supply agreements.

In an effort to mitigate pressures from the challenging global coal market environment, we remain focused on cost containment activities and implemented programs across our global platform in 2012 to reduce our workforce and lower spending for outside services and contractors. Additionally, we remain focused on tightening capital spending and have reduced 2013 capital spending targets by approximately half of 2012 levels to $450 to $550 million.

Dodd-Frank Act - Derivatives Regulation. On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) was enacted, which among other things, requires the Commodity Futures Trading Commission (CFTC) and the SEC to adopt new comprehensive regulations related to financial derivative transactions. Though the CFTC and SEC have finalized many definitions and rule makings, they have yet to complete their efforts in this area and the full impact of the new regulatory regime is not yet known. We believe that we are eligible for the commercial end-user exemption available under the Dodd-Frank Act and will need to be in full compliance with these regulations by the second quarter of 2013. We expect that the Dodd-Frank Act will primarily impact us through an increase in compliance and transaction costs associated with our corporate hedging and trading and brokerage activities. The legislation is not expected to have an impact on our trading strategies utilized to hedge or mitigate risk related to asset production and commercial activities.

European Markets Infrastructure Regulation. In July 2012, the European Commission adopted the European Markets Infrastructure Regulation (EMIR) related to over-the-counter derivatives, central counterparties, and Trade Repositories. EMIR ensures that information on all European derivative transactions will be reported to trade repositories and accessible to supervisory authorities, including the European Securities and Markets Authority (ESMA). The regulation also requires standard derivative contracts to be cleared through Central Counterparties (CCPs) as well as margins for uncleared trades and establishes stringent organizational, business conduct and prudential requirements for these CCPs. In December 2012, the European Commission adopted technical standards complimenting the regulation. We are currently assessing the impacts of the new standards. We do expect that they will increase compliance and transaction costs associated with our hedging and our Trading and Brokerage activities.

Markets in Financial Instruments. 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 corporate hedging and trading and brokerage activities. While the ultimate impact of these proposals will not be known for some time, we expect that they will increase compliance and transaction costs associated with our corporate hedging and trading and brokerage activities.

Minerals Resource Rent Tax. On March 29, 2012, Australia passed legislation creating a minerals resource rent tax (the MRRT) effective from July 1, 2012. The MRRT is a profits-based tax of our existing and future Australian coal projects at an effective tax rate of 22.5%. Under the MRRT, taxpayers are able to elect a market value asset starting base for existing projects which allows for the fair market value of the tenements to be deducted over the life of the mine as an allowance against MRRT. The market value allowance, and ultimately any future benefit, is subject to numerous uncertainties, including review and approval by the Australian Tax Office, realization only after other MRRT allowances provided under the law and estimates of long-term pricing and cost data necessary to estimate the future benefit and any MRRT liability. We have evaluated the provisions of the new tax and assessed recoverability of deferred tax assets and the valuation of liabilities associated with the implementation of the MRRT. As of December 31, 2012, we have recorded a net deferred tax liability of $77.6 million related to the market value starting base. Refer to Note 10. "Income Taxes" to the accompanying consolidated financial statements for additional information related to the implementation of the MRRT in 2012.

Carbon Pricing Framework. The Australian government's carbon pricing framework commenced on 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 average $1.00 to $2.00 Australian dollars per tonne of coal produced annually. Actual results will depend upon the volume of tonnes produced at each of our Australian 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 have applied 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 five-year period. Those sites received payments totaling $22.5 million Australian dollars in June related to this program, with similar payments expected in each of the next four years. We also may be eligible for a portion of the government's $70.0 million Australian dollars Coal Mining Abatement Technology Support Package over five years to support the development and deployment of technologies to reduce fugitive emissions from coal mines. Net of transition benefits, we recognized expenses of $11.9 million Australian dollars in 2012 related to this program, all of which were incurred in the second half of that year.

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Queensland Royalty. In September 2012, the State of Queensland announced new royalty rates on coal prices. The royalty change went into effect on October 1, 2012 and raised the royalty payment to the State of Queensland on coal prices over $100 per tonne from 10% to 12.5% for pricing up to $150 per tonne and 15% on pricing over $150 per tonne. There was no change to the 7% rate for coal sold below $100 per tonne. The impact of these new royalty rates will depend upon the volume of tonnes produced at each of our Queensland mining locations and coal prices received on those tonnes.

Cross State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA finalized the 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 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 were to 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 the rule and advised that the EPA is expected to continue administering the Clean Air Interstate Rule (CAIR) until the pending challenges are resolved. The court vacated the CSAPR on August 21, 2012, in a 2 to 1 decision, concluding that the rule was beyond the EPA's statutory authority. On October 5, 2012, the EPA petitioned for en banc review of that decision by the entire U.S. Court of Appeals for the District of Columbia Circuit, which denied the EPA's petition on January 24, 2013.

Proposed New Source Performance Standards (NPNS) for Fossil Fuel-Fired Electricity Utility Generating Units. On April 13, 2012, the EPA published for comment proposed new source performance standards for emissions of carbon dioxide for new fossil fuel-fired electric utility generating units. If these standards are adopted as proposed, it is unlikely, with a few possible exceptions, that any new coal-fired electric utility generating units could be constructed in the U.S. without the use of CCS technologies. The EPA has not yet finalized rules for modified or existing sources. We believe that any final rules issued by the EPA in this area will be challenged. The EPA is required to finalize those final rules by April 2013 or re-propose new standards.

Mercury and Air Toxics Standards. On December 16, 2011, the EPA issued the Mercury and Air Toxic Standards (MATS), which imposes Maximum Achievable Control Technology (MACT) emission limits on hazardous air emissions from new and existing coal-fueled electric generating plants. The rule also revised NSPS for nitrogen oxides, sulfur dioxides and particulate matter for new and modified coal-fueled electricity generating plants. The MACT rule provides three years for compliance and a possible fourth year as a state permitting agency may deem necessary. On November 30, 2012, the EPA published proposed reconsidered MACT new plant standards that the EPA has indicated it will finalize in March 2013. These proposed reconsidered standards are less stringent in some aspects than the standards issued in December 2011.

Long-Term Outlook

While the recent declines in global coal prices due to the stagnant economic conditions and increased supply in 2012 has tempered near-term expectations, our long-term global outlook remains positive, particularly in the Pacific markets. With global pricing currently at low levels, we expect long-term pricing growth will come off a smaller base than anticipated previously. According to the BP Statistical Review of World Energy 2012, coal has been the fastest growing major fuel in the world for the past decade. Wood Mackenzie projects that coal will overtake oil as the world's largest energy source in 2013. The International Energy Agency (IEA) estimates in its World Energy Outlook 2012, current policies scenario, that worldwide primary energy demand will grow 47% between 2010 and 2035. Demand for coal during this time period is projected to rise 59%, and the growth in global electricity generation from coal is expected to be greater than the growth in oil, natural gas, nuclear, hydro, geothermal and solar combined. China and India are expected to account for more than 75% of the coal-based primary energy demand growth projected from 2010 to 2035.

Under the current policies scenario, the IEA expects coal to retain its strong presence as a fuel for the power sector worldwide. Coal's share of the power generation mix was 41% in 2010. By 2035, the IEA estimates coal's fuel share of power generation to be 42% as it continues to have the largest share of worldwide electric power production.

The IEA projects that global natural gas-fueled electricity generation will have a compound annual growth rate of 2.7%, from 4.8 trillion kilowatt hours in 2010 to 9.3 trillion kilowatt hours in 2035. The total amount of electricity generated from natural gas is expected to be a little over one-half the total for coal, even in 2035. Renewables are projected to comprise 23% of the 2035 fuel mix versus 20% in 2010. Nuclear power is expected to grow 42%, however its share of total generation is expected to fall from 13% to 10% between 2010 and 2035. The planned shutdown of nuclear power plants in Japan and Germany may impact these projections. Generation from liquid fuels is projected to decline an average of 1.6% annually to 1.7% of the 2035 generation mix.

In the U.S., coal remains a significant fuel for electricity generation, but its share is expected to decline through 2040 due to competition from natural gas and renewables according to the EIA's 2013 Annual Energy Outlook Early Release.

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We believe that Btu Conversion applications such as CTG and CTL plants represent an avenue for potential long-term industry growth. A number of CTG, CTL and coal-to-chemical facilities are 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 pursuing multiple 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 third party coal and partnerships to utilize our mining experience for joint mine development, such as projects we are exploring in Xinjiang, China and the Tavan Tolgoi project in the South Gobi region of Mongolia.

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., some of its states or 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 from the sale of our coal production to customers and our trading and brokerage activities. To a lesser extent, we also generate cash from the sale of non-strategic assets, including coal reserves and surface lands, and, from time to time, the issuance of securities.

We follow a diversified investment approach for our cash and cash equivalents by maintaining such funds with a diversified portfolio of banks within our group of relationship banks in high quality, highly liquid investments with original maturities of three months or less, generally comprised of money market funds, term deposits and government securities. We monitor the amounts held with each bank on a routine basis and do not believe our cash and cash equivalents are exposed to any material risk of principal loss.

We hold cash balances within the U.S. and in several foreign locations around the world. As of December 31, 2012, approximately $300 million of our cash was held by U.S. entities, with the remaining balance held by foreign subsidiaries in accounts predominantly domiciled in the U.S. A significant majority of the cash held by our foreign subsidiaries is denominated in U.S. dollars. This cash is generally used to support non-U.S. liquidity needs, including capital and operating expenditures in Australia and the foreign operations of our Trading and Brokerage segment. Under current law, earnings repatriated to the U.S. are subject to U.S. federal income tax, less applicable foreign tax credits. We have not provided deferred taxes on foreign earnings because such earnings are considered to be indefinitely reinvested outside of the U.S. Accordingly, we utilize a variety of tax planning and financing strategies with the objective of having our worldwide cash available in the locations where it is needed. When appropriate, we may access our foreign cash in a tax efficient manner. Where local regulations or other circumstances may limit an efficient intercompany transfer of amounts held outside of the U.S., we will continue to utilize those funds for local liquidity needs. We do not expect restrictions or potential taxes on the repatriation of amounts held outside the U.S. to have a material effect on our overall liquidity, financial condition or results of operations.

In addition to cash and cash equivalents, our liquidity includes the available balances from our revolving credit facility (the Revolver) under our senior unsecured credit facility entered into in 2010 (the Credit Facility) and an accounts receivable securitization program. Our available liquidity as of December 31, 2012 was $2.2 billion, which was substantially comprised of $1.4 billion available for borrowing under the Revolver (net of outstanding letters of credit of $105.4 million), cash and cash equivalents of approximately $0.6 billion and available capacity under our accounts receivable securitization program of $191.5 million.

Capital Requirements

Our primary uses of cash include the cash costs of coal production and sale, capital expenditures, coal reserve lease and royalty payments, debt service costs (including interest and principal), capital and operating lease payments, postretirement plans, take or pay obligations, past mining retirement obligations and the payment of dividends.

We expect our available liquidity and cash flows from operations will be sufficient to meet our anticipated capital requirements during 2013 and for the foreseeable future. We routinely monitor our current and expected capital requirements and capital market conditions to evaluate the use of alternative financing sources, which include our ability to offer and sell securities under our shelf registration statement and access to credit markets.

Based on our current financial condition and credit relationships, we believe that we currently have the ability to access capital markets, if needed. Any adverse changes in our financial condition or liquidity or additional uncertainty in capital markets could negatively impact our ability to access such funds and, in turn, reduce the availability of our cash flows to fund discretionary spending, including capital expenditures for growth and development projects, acquisitions, share repurchases, dividend payments, contributions to our postretirement plans in excess of regulatory requirements and voluntary debt repayments.

Additions to Property, Plant, Equipment and Mine Development. We generally fund our capital additions with cash generated from operations. Accordingly, we evaluate our capital project portfolio on an ongoing basis and believe we have the appropriate flexibility to adjust our growth capital spending as appropriate based on any material changes in our cash flows from operations and liquidity position. In response to the challenging environment that characterized global coal markets in 2012, we expect to significantly reduce aggregate capital additions from 2012 levels of $996.7 million to between $450 million and $550 million in 2013. That spend will be predominantly allocated to capital required to maintain the existing productive capacity of our global coal mining platform, initiate the conversion of our Wambo Open-Cut Mine in Australia to owner-operated status and complete similar late-stage conversions at our Wilpinjong and Millennium mines in that region. Other late-stage Australian growth and development projects included in our 2013 capital expenditure projections include the modernization of our Metropolitan Mine operations and the installation of top coal caving technology and coal preparation plant upgrades at our North Goonyella Mine. We currently plan to defer certain new and early-stage growth and development projects across our global platform to time periods beyond 2013 and continue to evaluate the timing associated with those projects based on changes in global coal market demand.

Federal Coal Lease Expenditures. Federal coal lease expenditures, which pertain to U.S. federal coal reserves we lease from the U.S. Bureau of Land Management in support of our Western U.S. Mining segment operations, amounted to $276.5 million in 2012. We currently anticipate that our annual federal coal lease expenditures will total $272.8 million in 2013 through 2015 (net of annual true-up payments due to us from Alpha Natural Resources, Inc. (Alpha) pursuant to the federal coal lease swap transaction described in Note 24. "Commitments and Contingencies" to the consolidated financial statements) and $248.0 million in 2016. These expenditures may increase in 2013 and beyond depending upon our participation in and the successful bidding on future federal coal leases.

Total Indebtedness: We target our debt levels after considering a number of factors, including cash flow expectations, capital requirements, a target capital structure, our cost of capital and planned discretionary spending. Our total indebtedness as of December 31, 2012 and 2011, consisted of the following:

	December 31,	
	2012	2011
	(Dollars in millions)	
Term Loan	$418.8	$468.8
2011 Term Loan Facility	912.5	1,000.0
7.375% Senior Notes due November 2016	650.0	650.0
6.00% Senior Notes due November 2018	1,518.8	1,600.0
6.50% Senior Notes due September 2020	650.0	650.0
6.25% Senior Notes due November 2021	1,339.6	1,500.0
7.875% Senior Notes due November 2026	247.4	247.3
Convertible Junior Subordinated Debentures due December 2066	377.4	375.2

Capital lease obligations	104.6	122.8
Other	33.8	43.4
Total	$6,252.9	$6,657.5

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Certain of our long-term debt arrangements contain various administrative, reporting, legal and financial covenants. When in compliance with our financial covenants and customary default provisions, we are not restricted in our ability to pay dividends, sell assets and make redemptions or repurchase capital stock with proceeds received from the concurrent issue of capital stock or indebtedness. As of December 31, 2012, we were in compliance with all such covenants. On November, 16, 2012, we amended our Credit Facility and 2011 Term Loan Facility to temporarily increase the related maximum consolidated leverage coverage ratio covenant through December 31, 2014 in order to maintain our financial flexibility and accommodate the effects of expected near-term challenges facing global coal markets, as discussed in the "Outlook" section to this Item 7.

As market conditions warrant, we may from time to time repurchase debt securities issued by us, in privately negotiated or open market transactions, by tender offer or otherwise. During the second quarter of 2012, we repurchased $81.2 million and $160.4 million in aggregate principal amount of our 6.00% and 6.25% Senior Notes due 2018 and 2021, respectively, with existing cash on hand. In the fourth quarter of 2012, we voluntarily prepaid $25.0 million and $50.0 million in aggregate principal amount related to our Term Loan and 2011 Term Loan Facility, respectively. Those repurchases and voluntary prepayments reflect our current focus on balancing our capital structure through deleveraging.

Dividends. We have declared and paid quarterly dividends since our initial public offering in 2001, including $91.9 million of dividends paid in 2012. In January 2013, our Board of Directors approved a dividend of $0.085 per share of common stock, payable on February 28, 2013. The declaration and payment of dividends in the future and the amount of those dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt covenants and other factors deemed relevant by our Board of Directors.

Share Repurchases. During the second quarter of 2012, we utilized existing cash on hand to repurchase 4.2 million shares of our outstanding common stock for $99.9 million pursuant to the authority of our Chairman and Chief Executive Officer. As of December 31, 2012, our remaining available capacity for share repurchases under our publicly-announced repurchase program authorized by our Board of Directors was $700.4 million. 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.

Margin. As part of our trading and brokerage activities, we may be eligible to receive or required to post margin with an exchange or certain of our over-the-counter contract counterparties. The amount and timing of margin posted can vary with the volume of trades and market price volatility. Total net margin held by us at December 31, 2012 and 2011 was $133.2 million and $18.1 million, respectively. For the years ended December 31, 2012 and 2011, net cash inflows for margin were $115.1 million and $210.2 million, respectively.

Pension Contributions. Annual contributions to our qualified plans are made in accordance with minimum funding standards and our agreement with the Pension Benefit Guaranty Corporation (PBGC). Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). On July 6, 2012, the Moving Ahead for Progress in the 21st Century Act (MAP-21), a highway reauthorization and student loan bill that included both pension funding stabilization provisions and PBGC premium increases, was signed into law. The pension funding stabilization provisions temporarily increased the discount rates used to determine pension liabilities for purposes of minimum funding requirements. MAP-21 is not expected to change our total required cash contributions over the long term, but is expected to reduce our required cash contributions through 2015 relative to prior law if current interest rate levels persist and the qualified plans' asset returns are in line with expectations. As of December 31, 2012, our qualified plans are expected to be at or above the Pension Protection Act thresholds and will therefore avoid benefit restrictions and at-risk penalties for 2013. We contributed $1.7 million to our pension plans in 2012 and expect to contribute approximately $5 million to those plans in 2013.

Newcastle Coal Infrastructure Group (NCIG). Financing for phase one of stage two of construction closed in 2010 with us providing our pro-rata share of funding of $54.8 million. We disposed of the debt securities received in connection with that funding during 2010 and 2011. New debt securities for our pro-rata funding of the next phase of NCIG's port expansion were purchased during 2011 for $29.4 million, which were subsequently sold in 2012 for proceeds of $29.2 million.

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 October 19, 2015), after 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, debt securities, preferred stock, warrants and units.

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Historical Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2012 and 2011, as reported in the accompanying consolidated financial statements:

	Year Ended December 31,		Increase (Decrease) to Cash Flow	
	2012	2011	$	%
	(Dollars in millions)			
Net cash provided by operating activities	$1,515.1	$1,633.2	$(118.1)	(7.2)%
Net cash used in investing activities	(1,092.1)	(3,807.8)	2,715.7	(71.3)%
Net cash (used in) provided by financing activities	(663.3)	1,678.5	(2,341.8)	(139.5)%
Net change in cash and cash equivalents	(240.3)	(496.1)	255.8	(51.6)%
Cash and cash equivalents at beginning of period	799.1	1,295.2	(496.1)	(38.3)%
Cash and cash equivalents at end of period	$558.8	$799.1	$(240.3)	(30.1)%

Operating Activities. The decrease in net cash provided by operating activities for the year ended December 31, 2012 compared to the prior year was driven by the following:

- A year-over-year decrease in Adjusted EBITDA results;
- Decreased utilization of our accounts receivable securitization program compared to the prior year;
- Higher expenditures for cash interest expense due to debt added in connection with the acquisition of PEA-PCI in the fourth quarter of 2011;
- The timing of disbursements associated with our accounts payable and certain accrued liabilities; and
- Higher inventory builds corresponding with the impact of presently challenged global coal markets on demand; partially offset by
- Strong accounts receivable collection in 2012 compared to 2011;
- The monetization of $151.8 million of foreign currency hedge positions in the fourth quarter of 2012; and
- Lower pension contributions required in 2012 compared to the prior year;

Investing Activities. The reduction in net cash used in investing activities for the year ended December 31, 2012 compared to the prior year was driven by the following:

- Acquisition payments of $2.8 billion disbursed in 2011 associated with our purchase of PEA-PCI;
- Greater proceeds from the disposal of assets of $107.8 million driven by current year collections of $34.2 million on a long-term receivable related to a prior sell down of the Codrilla Mine Project by PEA-PCI into the Coppabella Moorvale Joint Venture prior to our acquisition of PEA-PCI in 2011, $21.3 million in aggregate reimbursement and true up payments received in 2012 related to our federal coal lease swap executed with Alpha and $37.2 million in proceeds received in 2012 from sale-leaseback transactions on operating equipment from our Australian Mining segment; and
- Lower expenditures of $25.5 million related to our involvement in the Prairie State development project, which commenced commercial operations in 2012; partially offset by
- Higher federal coal lease expenditures associated with our Western U.S. Mining operations of $234.1 million due to additional federal coal lease agreements executed in 2012.

Financing Activities. The decline in net cash (used in) provided by financing activities for the year ended December 31, 2012 compared to the prior year was driven by the following:

- Debt proceeds of $4.1 billion received in the prior year that were used, in part, to fund the PEA-PCI acquisition; and
- Higher long-term debt payments of $151.9 million as a result of an increase in debt repurchases and voluntary debt prepayments over the prior year period, in addition to higher overall debt levels to service in 2012 due to the prior year PEA-PCI acquisition; and
- Current year common stock repurchases of $99.9 million; partially offset by
- Higher spend in the prior year of $1.9 billion associated with the acquisition of noncontrolling interests related to the PEA-PCI acquisition.

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Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2012:

	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)	$9,399.9	$373.3	$1,248.7	$2,080.3	$5,697.6
Capital lease obligations (principal and interest)	125.4	42.2	37.8	22.0	23.4
Operating lease obligations	677.5	145.1	245.6	183.9	102.9
Unconditional purchase obligations(1)	494.6	457.9	36.7	—	—
Coal reserve lease and royalty obligations(2)	1,126.1	282.2	558.4	257.2	28.3
Take or pay obligations(3)	4,355.4	424.3	850.0	120.4	2,960.7
Other long-term liabilities(4)	3,178.0	171.8	323.9	302.3	2,380.0
Total contractual cash obligations	$19,356.9	$1,896.8	$3,301.1	$2,966.1	$11,192.9

(1) We routinely enter into purchase agreements with approved vendors for most types of operating expenses in the ordinary course of business. 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 and though they are considered enforceable and legally binding, the related terms generally allow us the option to cancel, reschedule or adjust our requirements based on our business needs prior to the delivery of goods or performance of services. Accordingly, the commitments in the table above relate to orders to suppliers for capital purchases. These purchase obligations for capital expenditures relate to maintenance capital necessary to preserve the productive capacity of our existing mines and the selective advancement of certain late-stage growth and development projects in Australia.

(2) Includes $1.1 billion of federal coal lease expenditures due in annual installments through 2016.

(3) Represents various long- and short-term take or pay arrangements in the U.S. and Australia 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.

(4) 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 $122.8 million of gross unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

Off-Balance Sheet Arrangements

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

Accounts Receivable Securitization. We have an accounts receivable securitization program (securitization program) with a maximum capacity of $275.0 million through our wholly-owned, bankruptcy-remote subsidiary (Seller). At December 31, 2012, we had $191.5 million available under the securitization program, net of amounts drawn. Under the securitization program, we contribute trade receivables of most of our U.S. subsidiaries on a revolving basis 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 of working capital. The securitization program extends to May 2013, at which time we expect to seek renewal of that program. The letter of credit commitment that supports the commercial paper facility underlying the securitization program must be renewed annually.

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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, 2012, we received total consideration of $4,377.8 million related to accounts receivable sold under the securitization program, including $2,834.5 million of cash up front from the sale of the receivables, an additional $1,247.7 million of cash upon the collection of the underlying receivables and $295.6 million that had not been collected at December 31, 2012 and was recorded at carrying value, which approximates fair value. The reduction in accounts receivable as a result of securitization activity with the Conduits was $25.0 million and $150.0 million at December 31, 2012 and 2011, respectively. Securitization activity has been reflected in the consolidated statements of cash flows as an operating activity because cash received from the Conduits upon the sale of receivables, as well as 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, $2.0 million and $2.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Patriot Bankruptcy. On October 31, 2007, we spun off companies that constituted portions of our former Eastern U.S. Mining operations business segment to form Patriot Coal Corporation (Patriot). The spin-off included eight company-operated mines, two majority-owned joint venture mines and numerous contractor-operated mines serviced by eight coal preparation facilities along, with 1.2 billion tons of proven and probable coal reserves. On July 9, 2012, Patriot and certain of its wholly owned subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Southern District of New York. The case was subsequently moved to the U.S. Bankruptcy Court for the Eastern District of Missouri.

We believe that our only material exposure to the bankruptcy of Patriot relates to up to $150 million in possible federal and state black lung occupational disease liabilities. As Patriot noted in its Annual Report on Form 10-K/A for the year ended December 31, 2011, it has posted $15 million in collateral with the U.S. Department of Labor (DOL) in exchange for the right to self-insure its liabilities under the Federal Coal Mine Health and Safety Act of 1969 (Black Lung Act). If Patriot is unable to meet its black lung liability obligations, we believe that the DOL will first look to this collateral for payment. The Black Lung Act allows the DOL to seek recovery from other potentially liable operators as well. We may be considered a potentially liable operator for purposes of the Black Lung Act with respect to the black lung liabilities of Patriot at the time of the spin-off.

On October 23, 2012, eight individual plaintiffs and the United Mine Workers of America filed a putative class action lawsuit in the U.S. District Court for the Southern District of West Virginia against Peabody Holding Company, LLC, Peabody Energy Corporation and an unrelated coal company. The lawsuit seeks to have the court obligate the defendants to maintain certain Patriot benefit plans at their current levels and to find the defendants actions in violation of the Employee Retirement Income Security Act of 1974. We believe that the lawsuit is without merit and will vigorously defend against it.

Other Off-Balance Sheet Arrangements. From time to time, we enter into coal off-take agreements with counterparties where, as a part of the arrangements, we may provide certain financial guarantees on behalf of the counterparties. To mitigate the associated risk, we place liens on the counterparties' production equipment or require performance bonds. As of December 31, 2012, we had been released of all guarantees relating to such agreements, which had amounted to $10.0 million as of the end of the prior year.

Bilateral Cash Collateralization Facilities. As of December 31, 2011, we used bilateral cash collateralization agreements whereby we posted an aggregate of $79.7 million in cash in lieu of issuing letters of credit available under the Credit Facility to support our maximum reimbursement obligation associated with our involvement in Dominion Terminal Associates and an agreement with the PBGC. Such collateral was considered readily available given our ability to substitute the amount posted with letters of credit at any time and classified within "Cash and cash equivalents" in our consolidated balance sheet accordingly. In 2012, we terminated both agreements and replaced the previously posted cash collateral with letters of credit under the Credit Facility.

Refer to Note 23. "Financial Instruments and Guarantees with Off-Balance-Sheet Risk" 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. 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, 2012 for postretirement benefit costs and pension liabilities totaled $139.7 million, while employer contributions were $66.8 million.

Each of these liabilities is actuarially determined and we use various actuarial assumptions, including the discount rate, future cost trends and expected asset returns 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 postretirement benefit costs. Our medical trend assumption is developed by annually examining the historical trend of 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 could affect our obligation to satisfy these or additional obligations.

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

	For Year Ended December 31, 2012	
	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Health care cost trend rate:		
Effect on total net periodic postretirement benefit cost	$18.1	$(15.6)
Effect on total postretirement benefit obligation	$107.5	$(93.0)

	For Year Ended December 31, 2012	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic postretirement benefit cost	$(3.8)	$4.2
Effect on total postretirement benefit obligation	$(52.3)	$59.7

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For our pension obligation, assumed discount rates and expected returns on assets have a significant effect on the expense and funded status amounts reported for our defined benefit pension plans. Below we have provided two separate sensitivity analyses to demonstrate the significance of these assumptions in relation to reported amounts.

	For Year Ended December 31, 2012	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic pension cost	$(8.6)	$9.2
Effect on defined benefit pension plans' funded status	$57.5	$(62.9)
Expected return on assets:		
Effect on total net periodic pension cost	$(3.9)	$3.9

See Note 15. "Postretirement Health Care and Life Insurance Benefits" and Note 16. "Pension and Savings Plans" to our consolidated financial statements for additional information regarding postretirement benefit and pension plans.

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, 2012 was $67.0 million, and payments totaled $19.9 million. See Note 14. "Asset Retirement Obligations" to our consolidated financial statements for additional information 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 evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. As of December 31, 2012, we had valuation allowances for income taxes totaling $714.9 million. 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. As of December 31, 2012, we had net unrecognized tax benefits of $119.7 million included in "Other noncurrent liabilities" in the consolidated balance sheet. We believe that our judgments and estimates are reasonable; however, to the extent we prevail in matters for which liabilities have been established, or are required to pay amounts in excess of our recorded liabilities, our effective tax rate in a given period could be materially affected.

See Note 10. "Income Taxes" to our consolidated financial statements for additional information regarding valuation allowance and unrecognized tax benefits.

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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.

Subsequent to the finalization of the purchase price allocation, any adjustments to the recorded values of acquired assets and liabilities would be reflected in the consolidated statements of operations. Once final, it is not permitted to revise the allocation of the original purchase price, even if subsequent events or circumstances prove the original judgments and estimates to be incorrect. The assumptions and judgments made when recording business combinations will have an impact on reported results of operations for many years into the future. See Note 2. "Acquisition of Macarthur Coal Limited" to our consolidated financial statements for additional information regarding business combinations.

Impairment of Long-Lived Assets. We evaluate our long-lived assets used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition. We generally do not view short-term declines in thermal and metallurgical coal prices in the markets in which we sell those products as a triggering event for conducting impairment tests because such markets have a history of price volatility. However, we generally do view a sustained trend of depressed coal market pricing (for example, over periods exceeding one year) as an indicator of potential impairment.

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. We generally group such assets at the mine level, or the mining complex level for mines that share infrastructure, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for transferability to ongoing operating sites, remaining economic life for use in reclamation-related activities or for expected salvage.

When indicators of impairment are present, we evaluate our long-lived assets used in operations for recoverability by comparing the estimated undiscounted cash flows expected to be generated by those assets under various assumptions to their carrying amounts. If such undiscounted cash flows indicate that the carrying value of the asset group is not recoverable, impairment losses are measured by comparing the estimated fair value of the asset group to its carrying amount. As quoted market prices are unavailable for our individual mining operations, fair value is determined through the use of an expected present value technique based on the income approach. The estimated future cash flows and underlying assumptions used to assess recoverability and, if necessary, measure the fair value of our long-lived assets are derived from those developed in connection with our planning and budgeting process. We believe our assumptions are consistent with those a market participant would use for valuation purposes.

Impairment of long-lived assets included in continuing operations was $833.6 million for the year ended December 31, 2012. The most critical assumptions underlying our projections include those surrounding future coal prices for unpriced coal, production costs (including costs for labor and commodity supplies), foreign currency exchange rates and a risk-adjusted, after-tax cost of capital, all of which constitute unobservable Level 3 inputs under the fair value hierarchy. The assumptions used are based on our best knowledge at the time we prepare our analysis but can vary significantly due to regulatory issues, unforeseen mining conditions, change in commodity prices, availability and costs of labor and changes in supply and demand. See Note 3. "Asset Impairment and Mine Closure Costs" to our consolidated financial statements for additional information regarding impairment charges.

Fair Value Measurements of Financial Instruments. 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.

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

At December 31, 2012 and 2011, 1% ($5.2 million) and 1% ($8.7 million), respectively, of our net financial assets were categorized as Level 3. See Note 7. "Derivatives and Fair Value Measurements" and Note 8. "Coal Trading" to our consolidated financial statements for additional information regarding derivative fair value measurements.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

See Note 1. "Summary of Significant Accounting Policies" 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 from our trading and brokerage activities.

We generally account for our coal trading activities using the fair value method, which requires us to reflect contracts with third parties that meet the definition of a derivative at market value in our consolidated financial statements, with the exception of contracts for which we have elected to apply the normal purchases and normal sales exception. Our trading portfolio included futures, forwards and swaps as of December 31, 2012. 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, which captures our potential loss exposure related to forward, swap and option positions. Our VaR model assumes a 5- to 15-day holding period dependent upon the products within our portfolio at the time of VaR measurement and produces an output corresponding with a 95% one-tailed confidence interval, which means that there is a one in 20 statistical chance that our portfolio could lose more than the VaR estimates during the assumed liquidation period. Our volatility calculation incorporates an exponentially weighted moving average algorithm based on price movements during 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 potential loss expected in the 5% of the time that changes in the portfolio value during the assumed liquidation period is expected to exceed measured VaR.

VaR analysis 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. Nonetheless, an inherent limitation of VaR is that past changes in market risk factors may not produce accurate predictions of future market risk. Due to that limitation, combined with the subjectivity in the choice of the liquidation period and reliance on historical data to calibrate our models, 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.

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During the year ended December 31, 2012, the actual low, high, and average VaR was $2.0 million, $9.3 million and $4.3 million, respectively.

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 (such as the forward sale of coal to be produced and/or purchased) may ultimately involve instruments sensitive to market risk, 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 analysis, as discussed above.

Future Realization. As of December 31, 2012, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio Total
2013	77%
2014	15%
2015	6%
2016	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, other industrial energy users, energy marketers and nonfinancial trading houses. 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, fuel and explosives and interest rate 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 and options to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 7 to our consolidated financial statements. Assuming we had no foreign currency 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 $145 million for 2013. Taking into consideration hedges currently in place, our net exposure to the same rate change is approximately $37 million for 2013. The notional amounts of our foreign currency hedge contracts as of December 31, 2012 are noted in the "Notional Amounts and Fair Value" section of Note 7. "Derivatives and Fair Value Measurements" to our consolidated financial statements, which information is incorporated by reference herein.

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Other Non-trading Activities — Commodity Price Risk

Long-Term Coal Contracts. We predominantly 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 89%, 91% and 91% of our worldwide sales (by volume) for the years ended December 31, 2012, 2011 and 2010, respectively. Substantially all of our coal in the U.S. is contracted in 2013 at planned production levels. We had 30% to 40% of seaborne thermal coal volumes available for pricing at January 29, 2013. We expect near-term macroeconomic movements to dictate quarterly metallurgical coal pricing for the remainder of 2013 and we are targeting total 2013 metallurgical coal sales of approximately 15 to 16 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 and explosives-related derivative swap contracts are noted in the "Notional Amounts and Fair Value" section of Note 7 to our consolidated financial statements, which is incorporated by reference herein. We expect to consume 165 to 170 million gallons of diesel fuel in 2013. 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 $40 million based on our expected usage. Taking into consideration hedges currently in place, our net exposure to the same change in the price of crude oil is approximately $13 million.

We expect to consume 330,000 to 340,000 tons of explosives during 2013 in the U.S. Explosives costs in Australia are generally included in the fees paid to our contract miners. Assuming we had no hedges in place, a price change in natural gas (often a key component in the production of explosives) of one dollar per million MMBtu would result in an increase or decrease in our annual explosives costs of approximately $6 million based on our expected usage. Taking into consideration hedges currently in place, our net exposure to the same change in the price of natural gas is approximately $3 million.

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 7 to our consolidated financial statements. As of December 31, 2012, we had $4.9 billion of fixed-rate borrowings and $1.3 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 $13 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 $294 million in the estimated fair value of these borrowings.

Item 8. Financial Statements and Supplementary Data.

See Part IV, Item 15. "Exhibits, Financial Statement Schedules" of this report for the 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, 2012, 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, 2012, 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. There have been no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2012 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, 2012.

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 25, 2013

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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, 2012, 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.

In our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012 of Peabody Energy Corporation and our report dated February 25, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
St. Louis, Missouri
February 25, 2013

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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 2013 Proxy Statement and in Part I, Item 1. "Business" 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 2013 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 2013 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 2013 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, 2012:

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	1,451,945	(1)	$37.90	(2)	14,523,932	(3)
Equity compensation plans not approved by security holders	—		—		—	
Total	1,451,945		$37.90		14,523,932	

(1) Includes 84,232 shares issuable pursuant to outstanding deferred stock units and 41,762 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 1,832,591 shares available for issuance under our U.S. Employee Stock Purchase Plan and 932,304 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 2013 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 2013 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Documents Filed as Part of the Report

(1) Financial Statements.

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

	Page
Report of Independent Registered Public Accounting Firm	F-1
Consolidated Statements of Operations — Years Ended December 31, 2012, 2011 and 2010	F-2
Consolidated Statements of Comprehensive Income — Years Ended December 31, 2012, 2011 and 2010	F-3
Consolidated Balance Sheets — December 31, 2012 and December 31, 2011	F-4
Consolidated Statements of Cash Flows — Years Ended December 31, 2012, 2011 and 2010	F-5
Consolidated Statements of Changes in Stockholders’ Equity — Years Ended December 31, 2012, 2011 and 2010	F-7
Notes to Consolidated Financial Statements	F-8

(2) Financial Statement Schedule.

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

	Page
Valuation and Qualifying Accounts	F-79

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 25, 2013

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 25, 2013
/s/ MICHAEL C. CREWS Michael C. Crews	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 25, 2013
/s/ WILLIAM A. COLEY William A. Coley	Director	February 25, 2013
/s/ WILLIAM E. JAMES William E. James	Director	February 25, 2013
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 25, 2013
/s/ M. FRANCES KEETH M. Frances Keeth	Director	February 25, 2013
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 25, 2013
/s/ ROBERT A. MALONE Robert A. Malone	Director	February 25, 2013
/s/ WILLIAM C. RUSNACK William C. Rusnack	Director	February 25, 2013
/s/ JOHN F. TURNER John F. Turner	Director	February 25, 2013
/s/ SANDRA VAN TREASE Sandra Van Trease	Director	February 25, 2013
/s/ ALAN H. WASHKOWITZ Alan H. Washkowitz	Director	February 25, 2013

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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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at 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 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, 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 25, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
St. Louis, Missouri
February 25, 2013

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions, except per share data)		
Revenues			
Sales	$7,041.7	$7,013.0	$6,139.6
Other revenues	1,035.8	882.9	528.6
Total revenues	8,077.5	7,895.9	6,668.2
Costs and expenses			
Operating costs and expenses	5,932.7	5,477.6	4,637.7
Depreciation, depletion and amortization	663.4	474.3	429.5
Asset retirement obligation expenses	67.0	52.6	45.9
Selling and administrative expenses	268.8	268.2	232.2
Acquisition costs related to Macarthur Coal Limited	—	85.2	—
Other operating (income) loss:			
Net gain on disposal or exchange of assets	(17.1)	(76.9)	(29.9)
Asset impairment and mine closure costs	929.0	—	—
Loss from equity affiliates	61.2	19.2	1.7
Operating profit	172.5	1,595.7	1,351.1
Interest expense	405.6	238.6	222.0
Interest income	(24.5)	(18.9)	(9.6)
(Loss) income from continuing operations before income taxes	(208.6)	1,376.0	1,138.7
Income tax provision	262.3	363.2	313.7
(Loss) income from continuing operations, net of income taxes	(470.9)	1,012.8	825.0
Loss from discontinued operations, net of income taxes	(104.2)	(66.5)	(22.8)
Net (loss) income	(575.1)	946.3	802.2
Less: Net income (loss) attributable to noncontrolling interests	10.6	(11.4)	28.2
Net (loss) income attributable to common stockholders	$(585.7)	$957.7	$774.0
(Loss) income from continuing operations			
Basic (loss) earnings per share	$(1.80)	$3.78	$2.96
Diluted (loss) earnings per share	$(1.80)	$3.77	$2.92
Net (loss) income attributable to common stockholders			
Basic (loss) earnings per share	$(2.19)	$3.53	$2.88
Diluted (loss) earnings per share	$(2.19)	$3.52	$2.84
Dividends declared per share	$0.340	$0.340	$0.295

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Net (loss) income	$(575.1)	$946.3	$802.2
Other comprehensive (loss) income, net of income taxes:			
Net change in unrealized gains (losses) on available-for-sale securities (net of $4.0 tax provision for 2012 and $3.9 tax benefit for 2011)			
Unrealized holding losses on available-for-sale securities	(15.5)	(5.8)	—
Less: Reclassification for realized losses (gains) included in net income	22.5	(0.9)	—
Net change in unrealized gains (losses) on available-for-sale securities	7.0	(6.7)	—
Net unrealized gains on cash flow hedges (net of $3.9 and $6.2 tax benefit for 2012 and 2011, respectively and $129.5 tax provision for 2010)			
Increase in fair value of cash flow hedges	350.4	291.9	229.9
Less: Reclassification for realized gains included in net income	(298.6)	(251.0)	(102.4)
Net unrealized gains on cash flow hedges	51.8	40.9	127.5
Postretirement plans and workers' compensation obligations (net of $43.9 tax provision for 2012 and $63.4 and $2.1 tax benefit for 2011 and 2010, respectively)			
Prior service cost (credit) for the period	20.1	0.9	(4.9)
Net actuarial loss for the period	—	(150.1)	(41.3)
Amortization of actuarial loss and prior service cost	55.4	40.5	34.3
Postretirement plan and workers' compensation obligations	75.5	(108.7)	(11.9)
Foreign currency translation adjustment	19.1	—	—
Other comprehensive income (loss), net of income taxes	153.4	(74.5)	115.6
Comprehensive (loss) income	(421.7)	871.8	917.8
Less: Comprehensive income (loss) attributable to noncontrolling interests	10.6	(11.4)	28.2
Comprehensive (loss) income attributable to common stockholders	$(432.3)	$883.2	$889.6

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	2011
	(Amounts in millions, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$558.8	$799.1
Accounts receivable, net of allowance for doubtful accounts of $13.7 at December 31, 2012 and $17.0 at December 31, 2011	737.8	922.5
Inventories	548.4	444.4
Assets from coal trading activities, net	52.4	44.6
Deferred income taxes	56.4	27.3
Other current assets	621.7	768.0
Total current assets	2,575.5	3,005.9
Property, plant, equipment and mine development		
Land and coal interests	10,947.7	10,630.5
Buildings and improvements	1,321.3	1,084.2
Machinery and equipment	3,162.2	2,857.3
Less: accumulated depreciation, depletion and amortization	(3,629.5)	(3,320.4)
Property, plant, equipment and mine development, net	11,801.7	11,251.6
Investments and other assets	1,431.8	2,475.5
Total assets	$15,809.0	$16,733.0
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$47.8	$101.1
Liabilities from coal trading activities, net	19.4	10.3
Accounts payable and accrued expenses	1,606.9	1,712.3
Total current liabilities	1,674.1	1,823.7
Long-term debt, less current maturities	6,205.1	6,556.4
Deferred income taxes	577.3	523.2
Asset retirement obligations	687.5	615.2
Accrued postretirement benefit costs	960.7	1,053.1
Other noncurrent liabilities	765.5	645.6
Total liabilities	10,870.2	11,217.2
Stockholders' equity		
Preferred Stock — $0.01 per share par value; 10.0 shares authorized, no shares issued or outstanding as of December 31, 2012 or December 31, 2011	—	—
Series A Junior Participating Preferred Stock - $0.01 per share par value; no shares authorized as of December 31, 2012 and 1.5 shares authorized as of December 31, 2011; no shares issued or outstanding as of December 31, 2012 or December 31, 2011	n.a.	—
Perpetual Preferred Stock — 0.8 shares authorized, no shares issued or outstanding as of December 31, 2012 or December 31, 2011	—	—
Series Common Stock — $0.01 per share par value; 40.0 shares authorized, no shares issued or outstanding as of December 31, 2012 or December 31, 2011	—	—
Common Stock — $0.01 per share par value; 800.0 shares authorized, 282.3 shares issued and 268.6 shares outstanding as of December 31, 2012 and 280.3 shares issued and 271.1 shares outstanding as of December 31, 2011	2.8	2.8

Additional paid-in capital	2,286.3	2,234.0
Retained earnings	3,066.4	3,744.0
Accumulated other comprehensive income (loss)	11.0	(142.4)
Treasury shares, at cost: 13.7 shares as of December 31, 2012 and 9.2 shares as of December 31, 2011	(461.6)	(353.3)
Peabody Energy Corporation's stockholders' equity	4,904.9	5,485.1
Noncontrolling interests	33.9	30.7
Total stockholders' equity	4,938.8	5,515.8
Total liabilities and stockholders' equity	$15,809.0	$16,733.0

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Cash Flows From Operating Activities			
Net (loss) income	$(575.1)	$946.3	$802.2
Loss from discontinued operations, net of income taxes	104.2	66.5	22.8
(Loss) income from continuing operations, net of income taxes	(470.9)	1,012.8	825.0
Adjustments to reconcile (loss) income from continuing operations, net of income taxes to net cash provided by operating activities:			
Depreciation, depletion and amortization	663.4	474.3	429.5
Noncash interest expense	20.7	15.5	12.8
Deferred income taxes	(2.6)	180.6	69.0
Share-based compensation	45.4	43.9	41.1
Asset impairment and mine closure costs	929.0	—	—
Net gain on disposal or exchange of assets	(17.1)	(76.9)	(29.9)
Loss from equity affiliates	61.2	19.2	1.7
Changes in current assets and liabilities:			
Accounts receivable	285.3	(221.0)	(149.4)
Change in receivable from accounts receivable securitization program	(125.0)	—	(104.6)
Inventories	(112.9)	(50.4)	(8.5)
Net assets from coal trading activities	125.2	172.4	(109.6)
Other current assets	10.3	(27.4)	(28.5)
Accounts payable and accrued expenses	(117.1)	83.3	222.9
Monetization of foreign currency hedge positions	151.8	—	—
Asset retirement obligations	46.4	30.4	29.9
Workers' compensation obligations	9.4	10.4	(8.9)
Accrued postretirement benefit costs	38.9	35.4	23.1
Pension costs	34.1	31.1	23.3
Contributions to pension plans	(1.7)	(46.7)	(112.6)
Other, net	26.0	(34.8)	(21.8)
Net cash provided by continuing operations	1,599.8	1,652.1	1,104.5
Net cash used in discontinued operations	(84.7)	(18.9)	(17.4)
Net cash provided by operating activities	1,515.1	1,633.2	1,087.1
Cash Flows From Investing Activities			
Additions to property, plant, equipment and mine development	(986.0)	(847.4)	(546.0)
Changes in accrued expenses related to capital expenditures	104.7	51.2	—
Federal coal lease expenditures	(276.5)	(42.4)	—
Investment in Prairie State Energy Campus	(10.7)	(36.2)	(76.0)
Proceeds from disposal of assets, net of notes receivable	147.9	40.1	19.1
Investments in equity affiliates and joint ventures	—	(39.7)	(18.8)
Purchases of debt and equity securities	(46.7)	(147.7)	(74.6)
Proceeds from sales of debt and equity securities	46.4	104.6	12.4
Purchases of short-term investments	(4.8)	(100.0)	—
Maturity of short-term investments	—	100.0	—
Acquisition of Macarthur Coal Limited, net of cash acquired	—	(2,756.7)	—

Contributions to joint ventures	(824.0)	(145.4)	—
Distributions from joint ventures	823.0	128.6	—
Advances to related parties	(148.0)	(371.3)	—
Repayment of loans from related parties	110.8	331.7	—
Other, net	(6.2)	(6.6)	(8.8)
Net cash used in continuing operations	(1,070.1)	(3,737.2)	(692.7)
Net cash used in discontinued operations	(22.0)	(70.6)	(10.9)
Net cash used in investing activities	(1,092.1)	(3,807.8)	(703.6)

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS - (Continued)

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Cash Flows From Financing Activities			
Repayments of long-term debt	$(415.8)	$(263.9)	$(1,167.3)
Proceeds from long-term debt	0.8	4,101.4	1,150.0
Payment of debt issuance costs	(6.9)	(61.5)	(32.2)
Dividends paid	(91.9)	(92.1)	(79.4)
Common stock repurchase	(99.9)	—	—
Repurchase of employee common stock relinquished for tax withholding	(8.4)	(18.7)	(13.5)
Excess tax benefits related to share-based compensation	8.3	8.1	51.0
Acquisition of MCG Coal Holdings Pty Ltd noncontrolling interests	(49.8)	—	—
Acquisition of PEAMCoal Pty Ltd noncontrolling interests	—	(1,994.8)	—
Other, net	0.3	—	14.3
Net cash (used in) provided by financing activities	(663.3)	1,678.5	(77.1)
Net change in cash and cash equivalents	(240.3)	(496.1)	306.4
Cash and cash equivalents at beginning of year	799.1	1,295.2	988.8
Cash and cash equivalents at end of year	$558.8	$799.1	$1,295.2

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Peabody Energy Corporation's Stockholders' Equity						
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Stockholders' Equity
	(Dollars in millions)						
December 31, 2009	$2.8	$2,067.7	$(321.1)	$2,183.8	$(183.5)	$6.2	$3,755.9
Net income	—	—	—	774.0	—	28.2	802.2
Net unrealized gains on cash flow hedges (net of $129.5 tax provision)	—	—	—	—	127.5	—	127.5
Postretirement plans and workers' compensation obligations (net of $2.1 tax benefit)	—	—	—	—	(11.9)	—	(11.9)
Dividends paid	—	—	—	(79.4)	—	—	(79.4)
Share-based compensation	—	41.1	—	—	—	—	41.1
Excess tax benefits related to share-based compensation	—	51.0	—	—	—	—	51.0
Stock options exercised	—	16.4	—	—	—	—	16.4
Employee stock purchases	—	5.8	—	—	—	—	5.8
Repurchase of employee common stock relinquished for tax withholding	—	—	(13.5)	—	—	—	(13.5)
Distributions to noncontrolling interests	—	—	—	—	—	(5.8)	(5.8)
December 31, 2010	$2.8	$2,182.0	$(334.6)	$2,878.4	$(67.9)	$28.6	$4,689.3
Net income (loss)	—	—	—	957.7	—	(11.4)	946.3
Net change in unrealized losses on available-for-sale securities (net of $3.9 tax benefit)	—	—	—	—	(6.7)	—	(6.7)
Net unrealized gains on cash flow hedges (net of $6.2 tax benefit)	—	—	—	—	40.9	—	40.9
Postretirement plans and workers' compensation obligations (net of $63.4 tax benefit)	—	—	—	—	(108.7)	—	(108.7)
Dividends paid	—	—	—	(92.1)	—	—	(92.1)
Share-based compensation	—	43.9	—	—	—	—	43.9
Excess tax benefits related to share-based compensation	—	8.1	—	—	—	—	8.1
Stock options exercised	—	4.8	—	—	—	—	4.8
Employee stock purchases	—	6.3	—	—	—	—	6.3
Repurchase of employee common stock relinquished for tax withholding	—	—	(18.7)	—	—	—	(18.7)
Macarthur Coal Limited noncontrolling interests at control	—	—	—	—	—	2,011.9	2,011.9

date							
Acquisitions of PEAMCoal Pty Ltd noncontrolling interests	—	(11.1)	—	—	—	(1,983.7)	(1,994.8)
Distributions to noncontrolling interests	—	—	—	—	—	(15.9)	(15.9)
Contributions from noncontrolling interests	—	—	—	—	—	1.2	1.2
December 31, 2011	$2.8	$2,234.0	$(353.3)	$3,744.0	$ (142.4)	$ 30.7	$5,515.8
Net (loss) income	—	—	—	(585.7)	—	10.6	(575.1)
Net change in unrealized gains on available-for-sale-securities (net of $4.0 tax provision)	—	—	—	—	7.0	—	7.0
Net unrealized gains on cash flow hedges (net of $3.9 tax benefit)	—	—	—	—	51.8	—	51.8
Postretirement plans and workers compensation obligations (net of $43.9 tax provision)	—	—	—	—	75.5	—	75.5
Foreign currency translation adjustment	—	—	—	—	19.1	—	19.1
Dividends paid	—	—	—	(91.9)	—	—	(91.9)
Share-based compensation	—	45.4	—	—	—	—	45.4
Excess tax benefits related to share-based compensation	—	8.3	—	—	—	—	8.3
Stock options exercised	—	2.4	—	—	—	—	2.4
Employee stock purchases	—	7.0	—	—	—	—	7.0
Repurchase of employee common stock relinquished for tax withholding	—	—	(8.4)	—	—	—	(8.4)
Common stock repurchase	—	—	(99.9)	—	—	—	(99.9)
MCG Coal Holdings Pty Ltd noncontrolling interests at conversion	—	—	—	—	—	39.0	39.0
Acquisition of MCG Coal Holdings Pty Ltd noncontrolling interests	—	(10.8)	—	—	—	(39.0)	(49.8)
Distributions to noncontrolling interests	—	—	—	—	—	(7.4)	(7.4)
December 31, 2012	$2.8	$2,286.3	$(461.6)	$3,066.4	$ 11.0	$ 33.9	$4,938.8

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (the Company) and its affiliates. Interests in subsidiaries controlled by the Company are consolidated with any outside shareholder interests reflected as noncontrolling interests, except when the Company has an undivided interests in an unincorporated joint venture. In those cases, the Company includes its proportionate share in the assets, liabilities, revenues and expenses of the jointly controlled entities within each applicable line item of the consolidated financial statements. All intercompany transactions, profits and balances have been eliminated in consolidation.

Description of Business

The Company is engaged in the mining of thermal coal for sale primarily to electric utilities and metallurgical coal for sale to industrial customers. The Company’s mining operations are located in the United States (U.S.) and Australia, in addition to equity-affiliate mining operations in Australia and Venezuela. The Company also markets and brokers coal from other coal producers, both as principal and agent, and trades coal and freight-related contracts through trading and business offices in China, Australia, the United Kingdom, Germany, Singapore, Indonesia, India and the U.S. The Company’s other energy-related commercial activities include participating in operations of a mine-mouth coal-fueled generating plant, the management of its coal reserve and real estate holdings and the development of Btu Conversion and clean coal technologies.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

In December 2011, the Financial Accounting Standards Board (FASB) issued accounting guidance, which was further clarified in January 2013, requiring additional information intended to help reconcile existing differences in balance sheet offsetting requirements under U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). While this standard leaves existing guidance surrounding the offsetting of financial assets and liabilities unchanged, it requires several additional disclosures, including gross and net information about instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to a master netting arrangement or similar agreement. The guidance will become effective for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods (January 1, 2013 for the Company). While the adoption of this guidance will impact the Company's disclosures, it will not affect the Company's results of operations, financial condition or cash flows.

In June 2011, the FASB issued accounting guidance eliminating the option to present the components of other comprehensive income as part of the statement of changes in stockholders’ equity and instead requiring an entity to present the components of net income, the components of other comprehensive income and the total of comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. That guidance also introduced new disclosure requirements, which were finalized in February 2013, requesting that entities provide additional information about reclassification adjustments out of accumulated other comprehensive income, including changes in accumulated other comprehensive income balances by component and significant reclassification items. The guidance became effective for interim and annual periods beginning after December 15, 2011 (January 1, 2012 for the Company), with the exception of the new disclosure requirements, which are effective for interim and annual periods beginning after December 15, 2012 (January 1, 2013 for the Company). The Company has reflected the new presentation of the components of net income and other comprehensive income and total comprehensive income in two separate, consecutive statements in its consolidated statements of operations and comprehensive income with no impact on its results of operations, financial condition or cash flows. While the adoption of the guidance surrounding the disclosure of items reclassified out of accumulated other comprehensive income will impact the Company's disclosures, it will not affect the Company's results of operations, financial condition or cash flows.

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In December 2010, the FASB issued guidance on accounting for business combinations that clarified a public entity’s disclosure requirements for pro forma presentation of revenue and earnings. If comparative statements are presented, the public entity should disclose revenue and earnings of the combined entity as though the business combination occurred as of the beginning of the comparable prior annual reporting period only. The guidance also requires the supplemental pro forma disclosures to include a description of the nature and amount of material nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The guidance was effective for business combinations for which the acquisition date was on or after the beginning of the first annual reporting period that began on or after December 15, 2010 (January 1, 2011 for the Company). The guidance impacted the Company’s disclosures with no impact on the Company’s results of operations, financial condition or cash flows.

In July 2010, the FASB issued accounting guidance to improve disclosures about the credit quality of an entity's financing receivables and the reserves held against them. End of reporting period disclosures became effective for reporting periods ended on or after December 15, 2010. Disclosures about activity that occurred during a reporting period became effective for interim and annual periods that began on or after December 15, 2010. While the guidance impacted the Company's disclosures related to credit quality of financing receivables and the allowance for credit losses, the adoption of this guidance had no impact on its results of operations, financial condition or cash flows.

In January 2010, the FASB issued accounting guidance that required new fair value disclosures, including disclosures about significant transfers into and out of Level 1 and Level 2 categories of the fair value hierarchy and a description of the reasons for the transfers. In addition, the guidance required new disclosures regarding activity in Level 3 fair value measurements, including a gross basis reconciliation. The Company began complying with the new fair value disclosure requirements beginning January 1, 2010, except for the disclosure of activity within Level 3 fair value measurements, which became effective January 1, 2011. In May 2011, the FASB issued additional fair value measurement disclosure requirements intended to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between U.S. GAAP and IFRS. That update required fair value hierarchy categorization for financial instruments not measured at fair value but for which disclosure of fair value is required, disclosure of all transfers between Level 1 and Level 2 categories and additional disclosures for Level 3 measurements regarding the sensitivity of fair value to changes in unobservable inputs and any interrelationships between those inputs. The guidance became effective for interim and annual periods beginning after December 15, 2011 (January 1, 2012 for the Company). While the adoption of this guidance impacted the Company's disclosures, it did not affect the Company's results of operations, financial condition or cash flows.

Sales

The Company’s revenue from coal sales is realized and earned when risk of loss passes to the customer. Under the typical terms of the Company’s coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the transportation source(s) that serves each of the Company’s mines. The Company incurs certain “add-on” taxes and fees on coal sales. Reported coal sales include taxes and fees charged by various federal and state governmental bodies and the freight charged on destination customer contracts.

Other Revenues

Other revenues include net revenues from coal trading activities as discussed in Note 8. "Coal Trading," as well as coal sales revenues that were derived from the Company’s mining operations and sold through the Company’s coal trading business. Also included are revenues from contract termination or restructuring payments, royalties related to coal lease agreements, sales agency commissions, farm income, property and facility rentals and generation development activities. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced.

Discontinued Operations and Assets Held for Sale

The Company classifies items within discontinued operations in the consolidated financial statements when the operations and cash flows of a particular component of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal (by sale or otherwise) and the Company will no longer have any significant continuing involvement in the operation of that component. Refer to Note 4. "Discontinued Operations" for additional details related to discontinued operations and assets held for sale.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Cash and Cash Equivalents
Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with original maturities of three months or less.
Inventories
Materials and supplies and coal inventory are valued at the lower of average cost or market. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Coal inventory costs include labor, supplies, equipment (including depreciation thereto), operating overhead and other related costs.
Investments in Marketable Securities
The Company’s short-term investments in marketable securities, which are included in "Other current assets" in the consolidated balance sheets, are defined as those investments with original maturities of greater than three months and up to one year. Long-term investments, which are included in "Investments and other assets" in the consolidated balance sheets, are defined as those investments with original maturities greater than one year.
The Company classifies its investments in debt securities as either held-to-maturity or available-for-sale at the time of purchase and reevaluates such designation periodically. Such investments are classified as held-to-maturity when the Company has the intent and ability to hold the securities to maturity. Investments in debt securities not classified as held-to-maturity and investments in marketable equity securities are classified as available-for-sale. Available-for-sale securities are carried at fair value, with unrealized gains and losses, net of income taxes, generally reported in “Accumulated other comprehensive income (loss)” in the consolidated balance sheets. Realized gains and losses, determined on a specific identification method, are included in “Interest income” in the consolidated statements of operations.
At each reporting date, the Company performs separate evaluations of its marketable securities to determine if any unrealized losses present are other than temporary. Such evaluations involve the consideration of several factors, including, but not limited to, the length of time the market value has been less than cost, the financial condition and near-term prospects of the issuer of the securities and whether the Company has the positive intent and ability to hold the securities until recovery. Refer to Note 3. "Asset Impairment and Mine Closure Costs" and Note 6. "Investments" for details regarding an other-than-temporary impairment loss of $35.5 million recognized during the year ended December 31, 2012 related to the Company's marketable equity securities holdings. There were no other-than-temporary impairment losses recorded during the years ended December 31, 2011 or 2010.
Property, Plant, Equipment and Mine Development
Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Capitalized interest in 2012, 2011 and 2010 was immaterial. Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Costs incurred to maintain current production capacity at a mine are charged to operating costs as incurred. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.
Coal reserves are recorded at cost, or at fair value in the case of nonmonetary exchanges of reserves or business acquisitions. The net book value of coal reserves, which excludes exploration properties, totaled $6.4 billion as of December 31, 2012 and $7.6 billion as of December 31, 2011. These coal reserves include mineral rights for leased coal interests and advance royalties that had a net book value of $5.2 billion as of December 31, 2012 and $6.3 billion as of December 31, 2011. The remaining net book value of coal reserves of $1.2 billion at December 31, 2012 and $1.3 billion at December 31, 2011 relates to coal reserves held by fee ownership. Amounts attributable to properties where the Company was not currently engaged in mining operations or leasing to third parties and, therefore, the coal reserves were not currently being depleted was $2.2 billion as of December 31, 2012 and $2.7 billion as of

December 31, 2011.

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

	Years
Building and improvements	4 to 29
Plant and equipment	3 to 43
Leasehold improvements	Shorter of Useful Life or Remaining Life of Lease

Equity and Cost Method Investments

The Company accounts for its investments in less than majority owned corporate joint ventures under either the equity or cost method. The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost and any difference between the cost of the Company’s investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company’s pro-rata share of the operating results of joint ventures and basis difference amortization is reported in the consolidated statements of operations in “Loss from equity affiliates.” Similarly, the Company's pro-rata share of the cumulative foreign currency translation adjustment of its equity method investments whose functional currency is not the U.S. dollar is reported in the consolidated balances sheet as a component of "Accumulated other comprehensive income (loss)," with periodic changes thereto reflected in the consolidated statements of comprehensive income.

The Company monitors its equity and cost method investments for indicators that a decrease in investment value has occurred that is other than temporary. Examples of such indicators include a sustained history of operating losses and adverse changes in earnings and cash flow outlook. In the absence of quoted market prices for an investment, discounted cash flow projections are used to assess fair value. If the fair value of an investment is determined to be below its carrying value and that loss in fair value is deemed other than temporary, an impairment loss is recognized. There were no impairment losses recorded during the years ended December 31, 2012, 2011 or 2010 associated with the Company's equity method investments. Refer to Note 3. "Asset Impairment and Mine Closure Costs" for details regarding impairment charges recognized during the year ended December 31, 2012 related to certain of the Company's cost method investments.

Included in the Company’s equity method investments is its joint venture interest in the Middlemount Mine in Australia, which was acquired in connection with the 2011 acquisition of PEA-PCI (see Note 2. "Acquisition of Macarthur Coal Limited" for additional details). In addition to that equity interest, the Company also periodically makes loans to the Middlemount Mine joint venture pursuant to the related shareholders' agreement, which is discussed further in Note 9. "Financing Receivables." The Company's other equity method investments include an interest in Carbones del Guasare S.A., which owns and operates the Paso Diablo Mine in Venezuela. The Company fully impaired the carrying value of that investment in 2009.

The table below summarizes the book value of the Company’s equity method investments, which is reported in “Investments and other assets” in the consolidated balance sheets, and the loss from its equity affiliates:

	Book Value at December 31,		Loss from Equity Affiliates for the Year Ended December 31,		
	2012	2011	2012	2011	2010
	(Dollars in millions)				
Equity interest in Middlemount Coal Pty Ltd	$295.9	$449.7	$52.1	$7.3	$—

Other equity method investments	2.7	76.9	9.1	11.9	1.7
Total equity method investments	$298.6	$526.6	$61.2	$19.2	$1.7

The Company's equity interest in Middlemount Coal Pty Ltd reflected in the table above includes a remaining unamortized difference between the book value of that investment and the underlying equity in the net assets of the joint venture of $143.1 million as of December 31, 2012.

In addition to impact of the loss from its equity method affiliates and changes to its pro-rata portion of the cumulative foreign currency translation adjustment of those affiliates, the book value of the Company's equity method investments was affected during the year ended December 31, 2012 by provisional fair value adjustments recorded during that period related to the purchase price allocation for the 2011 acquisition of PEA-PCI.

Asset Retirement Obligations

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

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

Contingent Liabilities

Accruals for other environmental and litigation matters are recorded in operating expenses when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Accrued contingent liabilities exclude claims against third parties and are not discounted. In general, costs related to environmental remediation and litigation are charged to expense. The current portion of these accruals is included in "Accounts payables and accrued expenses" and the long-term portion is included in "Other noncurrent liabilities" in the consolidated balance sheets.

Income Taxes

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

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

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions by accruing the costs of benefits to be provided over the employees' period of active service. These costs are determined on an actuarial basis. The Company's consolidated balance sheets reflect the accumulated postretirement benefit obligations of its postretirement benefit plans. See Note 15. "Postretirement Health Care and Life Insurance Benefits" for information related to postretirement benefits.

Pension Plans

The Company sponsors non-contributory defined benefit pension plans accounted for by accruing the cost to provide the benefits over the employees' period of active service. These costs are determined on an actuarial basis. The Company's consolidated balance sheets reflect the funded status of the defined benefit pension plans. See Note 16. "Pension and Savings Plans" for information related to pension plans.

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Derivatives

The Company recognizes at fair value all contracts meeting the definition of a derivative as assets or liabilities in the consolidated balance sheets, with the exception of certain coal trading contracts for which the Company has elected to apply a normal purchases and normal sales exception.

Gains or losses on derivative financial instruments designated as cash flow hedges are recorded as a separate component of stockholders' equity until the hedged transaction occurs (or until hedge ineffectiveness is determined), at which time gains or losses are reclassified to earnings. To the extent that the periodic changes in the fair value of a derivative exceeds the changes in the hedged item, the ineffective portion of the periodic non-cash changes are recorded in earnings in the period of the change. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes the mark-to-market movements in earnings in the period of the change. The potential for hedge ineffectiveness is present in the design of the Company's cash flow hedge relationships and is discussed in detail in Note 7. "Derivatives and Fair Value Measurements" and Note 8. "Coal Trading." Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in earnings, along with the offsetting gain or loss related to the underlying hedged item.

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

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

Business Combinations

The Company accounts for business combinations using the purchase method of accounting. The purchase method requires the Company 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.

Use of Estimates in the Preparation of the Consolidated Financial Statements

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

Impairment of Long-Lived Assets

The Company evaluates its long-lived assets used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition. The Company generally does not view short-term declines in thermal and metallurgical coal prices in the markets in which it sells those products as a triggering event for conducting impairment tests because such markets have a history of price volatility. However, the Company generally does view a sustained trend of depressed coal market pricing (for example, over periods exceeding one year) as an indicator of potential impairment.

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. The Company generally groups such assets at the mine level, or the mining complex level for mines that share infrastructure, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for transferability to ongoing operating sites, remaining economic life for use in reclamation-related activities or for expected salvage.

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When indicators of impairment are present, the Company evaluates its long-lived assets used in operations for recoverability by comparing the estimated undiscounted cash flows expected to be generated by those assets under various assumptions to their carrying amounts. If such undiscounted cash flows indicate that the carrying value of the asset group is not recoverable, impairment losses are measured by comparing the estimated fair value of the asset group to its carrying amount. As quoted market prices are unavailable for the Company's individual mining operations, fair value is determined through the use of an expected present value technique based on the income approach. The estimated future cash flows and underlying assumptions used to assess recoverability and, if necessary, measure the fair value of the Company's long-lived assets are derived from those developed in connection with the Company's planning and budgeting process. The Company believes its assumptions to be consistent with those a market participant would use for valuation purposes. The most critical assumptions underlying the Company's projections include those surrounding future coal prices for unpriced coal, production costs (including costs for labor and commodity supplies), foreign currency exchange rates and a risk-adjusted, after-tax cost of capital, which generally constitute unobservable Level 3 inputs under the fair value hierarchy.

Refer to Note 3. "Asset Impairment and Mine Closure Costs" for details regarding impairment charges recognized during the year ended December 31, 2012 related to long-lived assets. There were no impairment losses recorded during the years ended December 31, 2011 or 2010.

Fair Value

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

Foreign Currency

Functional currency is determined by the primary economic environment in which an entity operates, which for the Company's foreign operations is generally the U.S. dollar because sales prices in international coal markets and the Company's sources of financing those operations is denominated in that currency. Accordingly, substantially all of the Company’s consolidated foreign subsidiaries utilize the U.S. dollar as their functional currency. Monetary assets and liabilities are remeasured at year-end exchange rates while non-monetary items are remeasured at historical rates. Income and expense accounts are remeasured at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement related to tax balances are included as a component of "Income tax provision" while all other remeasurement gains and losses are included in "Operating costs and expenses." The total impact of foreign currency remeasurement on the consolidated statements of operations was a gain of $4.8 million for the year ended December 31, 2012 and losses of $0.9 million and $38.5 million for the years ended December 31, 2011 and 2010, respectively. The Middlemount Mine, in which the Company owns a 50% equity interest, utilizes the Australian dollar as its functional currency. Accordingly, the assets and liabilities of that equity investee are translated to U.S. dollars at the year-end exchange rate and income and expense accounts are translated at the average rate in effect during the year. The Company's pro-rata share of the translation gains and losses of the equity investee are recorded as a component of "Accumulated other comprehensive income (loss)." The total foreign currency translation gain recorded for the year ended December 31, 2012 was $19.1 million. No foreign currency translation gains or losses occurred in 2011 or 2010.

Share-Based Compensation

The Company accounts for share-based compensation at the grant date fair value of awards and recognizes the related expense over the vesting period of the awards. See Note 18. "Share-Based Compensation" for information related to share-based compensation.

Exploration and Drilling Costs

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

Advance Stripping Costs

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

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

(2) Acquisition of Macarthur Coal Limited

On October 23, 2011, PEAMCoal Pty Ltd (PEAMCoal), an Australian company that was then indirectly owned 60% by the Company and 40% by ArcelorMittal, acquired a majority interest in Macarthur Coal Limited (PEA-PCI or the acquiree) through an all cash off-market takeover offer. On October 26, 2011 (the acquisition and control date), the Company appointed its nominees to the acquiree's Board of Directors and executive management team. The acquisition was completed on December 20, 2011 as PEAMCoal acquired all of acquiree's remaining outstanding shares of common stock for $4.8 billion, net of $261.2 million of acquired cash, of which the Company's share was $2.8 billion (PEA-PCI acquisition). PEAMCoal accounted for share acceptances under the takeover process as a single transaction occurring on October 26, 2011. On December 21, 2011, the Company acquired ArcelorMittal Mining Australasia B.V., an indirect subsidiary of ArcelorMittal that indirectly owned 40% of PEAMCoal, for $2.0 billion resulting in the Company's 100% ownership of PEA-PCI.

Preliminary purchase price allocations were recorded in the accompanying consolidated financial statements as of the acquisition and control date. The Company finalized the fair value determination of the assets acquired and liabilities assumed upon the completion of third-party valuation appraisals during the year ended December 31, 2012. The following table summarizes the preliminary estimated fair values of assets acquired and liabilities assumed that were recognized at the acquisition and control date, as well as provisional fair value adjustments made during the year ended December 31, 2012:

	Preliminary Purchase Price Allocations	Provisional Adjustments	Final Purchase Price Allocations
	(Dollars in Millions)		
Accounts receivable, net	$106.6	$7.8	$114.4
Inventories	67.1	(11.4)	55.7
Other current assets	137.5	(3.9)	133.6
Property, plant, equipment and mine development	3,457.0	442.0	3,899.0
Investments and other assets	1,275.1	(394.0)	881.1
Current maturities of long-term debt	(11.0)	—	(11.0)
Accounts payable and accrued expenses	(133.8)	(21.9)	(155.7)
Long-term debt, less current maturities	(59.2)	—	(59.2)
Asset retirement obligations	(39.3)	(9.5)	(48.8)
Other noncurrent liabilities	(31.4)	(9.1)	(40.5)
Noncontrolling interests	(2,011.9)	—	(2,011.9)
Total purchase price, net of cash acquired of $261.2	$2,756.7	$—	$2,756.7

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Adjustments to the provisional fair values result from additional information obtained about facts in existence at the acquisition date. Adjustments between “Property, plant, equipment and mine development” and “Investments and other assets” were related to fair value adjustment allocations among various operating and exploration coal assets, including those associated with equity affiliate investments and an outstanding loan receivable, all of which are reflected as noncurrent assets on the Company's consolidated balance sheets. As such, prior financial statements have not been retroactively adjusted. The retroactive impact to the consolidated statement of operations from these provisional adjustments was recorded in the year ended December 31, 2012, which resulted in a $9.2 million decrease to "Depreciation, depletion and amortization," a $10.1 million decrease to "Operating costs and expenses" and a $5.6 million increase to "Loss from equity affiliates" during that period. These provisional adjustments were not material to the annual or quarterly periods affected.

In connection with the PEA-PCI acquisition, the Company acquired contract-based obligations consisting of port, rail and water take-or-pay obligations and recorded a liability for estimated unutilized capacity of $67.7 million which is being amortized based on that estimated unutilized capacity over the terms of the applicable agreements which extend to 2018. Unutilized capacity and the period of amortization were determined based on best estimates of forecasted usage at the acquisition date and may differ from actual capacity use. As of December 31, 2012, the carrying value of the liability was $50.0 million. The associated amortization (which is classified as a reduction to “Operating costs and expenses” in the consolidated statements of operations) recorded during the years ended December 31, 2012 and 2011 was $14.8 million and $2.9 million, respectively. Future amortization of the remaining carrying value of the liability as of December 31, 2012 is $18.1 million, $15.6 million, $11.6 million, $4.1 million and $0.6 million for the years ending December 31, 2013, 2014, 2015, 2016 and 2017, respectively.

The following unaudited pro forma financial information presents the combined results of operations of the Company and PEA-PCI, on a pro forma basis, as though the companies had been combined as of January 1, 2010. The unaudited pro forma financial information does not necessarily reflect the results of operations that would have occurred had the Company and PEA-PCI constituted a single entity during the periods presented or that may be attained in the future.

	Year Ended December 31,	
	2011	2010
	(Dollars in millions, except earnings per share)	
Revenue	$8,618.0	$7,387.7
Income from continuing operations, net of income taxes	1,305.7	1,002.4
Basic earnings per share	$3.55	$2.65
Diluted earnings per share	3.55	2.65

Pro forma income from continuing operations, net of income taxes, includes adjustments to operating costs and depreciation, depletion and amortization to reflect the additional expense for the estimated impact of fair value adjustments to coal inventory and property, plant and equipment (including mineral rights), respectively.

Included in "Investments and other assets" as of December 31, 2011 was a $368.9 million loan receivable from MCG Coal Holdings Pty Ltd (MCGH) that was initially measured based on the amount PEA-PCI loaned to MCGH. PEA-PCI had previously agreed to convert its receivable for a 90% equity interest in MCGH. The transaction was initially expected to be completed in May 2011. However, non-performance by a third party to the transaction resulted in PEA-PCI commencing litigation. The original loan balance was classified as a receivable pending the outcome of the legal proceedings. The loan receivable was subsequently adjusted downward during the measurement period based on the completion of a third-party valuation appraisal on the underlying net assets of MCGH, which were substantially comprised of mineral rights. In January 2012, the court ruled that the outstanding loan balance be converted to a 90% equity interest in MCGH, resulting in consolidation of MCGH and recognition of noncontrolling interests of $39.0 million at conversion. In June 2012, the Company acquired the remaining noncontrolling interests in MCGH for total consideration of $49.8 million. This acquisition was accounted for as an equity transaction as the Company previously maintained control of MCGH. Accordingly, the Company recorded a decrease to additional paid-in capital of $10.8 million related to this transaction, representing the difference between the consideration paid and the carrying value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(3) Asset Impairment and Mine Closure Costs

The following costs are reflected in "Asset impairment and mine closure costs" in the consolidated statement of operations for the year ended December 31, 2012:

	Reportable Segment				
	Australian Mining	Western U.S. Mining	Midwestern U.S. Mining	Corporate and Other	Consolidated
	(Dollars in millions)				
Charges related to mine closures:					
Impairment of long-lived assets	$—	$—	$26.9	$—	$26.9
Acceleration of asset retirement obligations	—	—	7.1	—	7.1
Employee termination benefits	—	—	6.7	—	6.7
Other	—	—	4.3	—	4.3
Other asset impairment charges:					
Long-lived assets held and used	806.7	—	—	—	806.7
Marketable securities	—	—	—	35.5	35.5
Cost method investments	—	—	—	39.4	39.4
Other	—	2.4	—	—	2.4
Total	$806.7	$2.4	$45.0	$74.9	$929.0

Long-Lived Assets Held and Used

Australian Mining. The Company observed a general weakening of international coal market conditions and a sustained trend of depressed seaborne metallurgical and thermal coal prices in 2012 compared with 2011 average prices, which was punctuated by the December 2012 settlement of first quarter 2013 seaborne coal prices at levels approximately 30% lower than those observed in the corresponding period one year prior. In spite of that decrease in coal prices and those of other commodities mined in Australia during that same period, the Company also noted a persistent strengthening of the Australian dollar compared to the U.S. dollar during 2012. As a result of those factors, the Company determined indicators of long-lived asset impairment to be present associated with its Australian Mining segment assets and conducted a review of those assets for recoverability in December 2012. Based on that evaluation, the Company determined that the long-lived assets of three of its surface mines that produce metallurgical coal (in whole or in part) were not recoverable and recognized an impairment charge of $806.7 million to write each of those mines down from their carrying value to their estimated fair value.

Western and Midwestern U.S. Mining. U.S. thermal coal markets experienced a downturn in production and consumption throughout 2012 driven by price competition with natural gas, weak U.S. economic activity and mild winter weather experienced in the first and fourth quarter of that year. The Company reviewed near-term projected operating metrics for each mine within those segments and determined that, in spite of those adverse conditions, no impairment was present in 2012.

Risks and Uncertainties. Because of the recent volatile nature of U.S. and international coal market conditions, it is reasonably possible that the Company's estimate of expected future cash flows may change in the near term, which may result in the need for further adjustments to the carrying value of the Company's long-lived mining assets.

Mine Closures

Willow Lake Mine. In November 2012, the Company announced the permanent closure of its Willow Lake Mine in Illinois due to a continued failure by the site to meet standards for safety, compliance and operating performance deemed acceptable by the Company. Because the performance obligations under the customer coal supply agreements previously serviced by the site were migrated to other mines within the Western and Midwestern U.S. Mining segments, the Willow Lake Mine continued to be classified in continuing operations for all periods presented. The results of that mine, prior to closing, were included in the Midwestern U.S. Mining segment. The Company recognized total charges of $45.0 million in the fourth quarter of 2012 in connection with the shutdown of this mine, which were primarily related to the impairment of long-lived assets, an acceleration in the timing of asset retirement obligations and employee termination benefits.

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Air Quality Mine. In September 2012, the Company announced it had permanently ceased production at its Air Quality Mine in Indiana due to uneconomic market conditions for the type of coal product previously produced at that site. The results of that mine, which were previously included within the Midwestern U.S. Mining reportable segment, have been reported as a discontinued operation for all periods presented because the operations and cash flows of the mine and the related coal product have been eliminated from the ongoing operations of the Company as a result of the mine closure. Refer to Note 4. "Discontinued Operations" for additional details regarding charges recognized during the year ended December 31, 2012 associated with this mine closure.

Marketable Securities

During the year ended December 31, 2012, the Company recognized an impairment charge of $35.5 million related to its investment in Winsway Coking Coal Holdings Limited (Winsway) marketable equity securities due to a decline in the fair value of that investment below its cost basis that was judged to be other than temporary. Accordingly, the unrealized loss previously recorded as a component of "Accumulated other comprehensive income (loss)" was reclassified to the consolidated statement of operations, thus resetting the cost basis of the Winsway marketable equity securities to their fair value as of December 31, 2012. Refer to Note 6. "Investments" for additional details.

Cost Method Investments

During the year ended December 31, 2012, the Company evaluated the commercial viability of the partnership projects underlying certain of its investments accounted for under the cost method due to adverse changes in the operating and regulatory environment surrounding those projects. As a result of that review, the Company concluded there to be significant doubt as to the ability of those projects to continue development and recorded an aggregate charge of $39.4 million in 2012 to fully impair the carrying value of those investments, the estimated fair values of which are considered nonrecurring Level 3 fair value measurements.

(4) Discontinued Operations

Discontinued operations include certain non-strategic Midwestern U.S. and Australian mining segment assets held for sale which the Company has committed to divest, Midwestern U.S. Mining Segment assets that have ceased production and other previously divested operations.

Results from discontinued operations were as follows during the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Total revenues	$229.1	$200.1	$277.5
Loss from Discontinued operations before income taxes	$(163.9)	$(88.8)	$(30.2)
Income tax benefit	59.7	22.3	7.4
Loss from Discontinued operations, net of income taxes	$(104.2)	$(66.5)	$(22.8)

Reflected in the results from discontinued operations for the year ended December 31, 2012 are total before- and after-tax charges of $116.7 million and $75.0 million, respectively, including a before- and after-tax impairment charge of $108.9 million and $68.8 million, respectively, recognized in connection with the shutdown of the Air Quality Mine in Indiana. Refer to Note 3. "Asset Impairment and Mine Closure Costs" for additional details surrounding that mine closure.

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Assets and liabilities classified as discontinued operations included in the Company's consolidated balance sheets were as follows:

	December 31, 2012	2011
	(Dollars in millions)	
Assets:		
Other current assets	$37.5	$24.6
Investments and other assets	140.8	232.2
Total assets classified as discontinued operations	$178.3	$256.8
Liabilities:		
Accounts payable and accrued expenses	$33.3	$63.9
Other noncurrent liabilities	27.1	59.6
Total liabilities classified as discontinued operations	$60.4	$123.5

(5) Inventories

Inventories consisted of the following:

	December 31, 2012	2011
	(Dollars in millions)	
Materials and supplies	$157.6	$123.7
Raw coal	164.3	108.1
Saleable coal	226.5	212.6
Total	$548.4	$444.4

(6) Investments

Investments in available-for-sale securities at December 31, 2012 were as follows:

Available-for-sale securities	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(Dollars in millions)			
Current:				
U.S. corporate bonds	$4.1	$—	$—	$4.1
Noncurrent:				
Marketable equity securities	32.4	—	—	32.4
Federal government securities	32.0	0.2	—	32.2
U.S. corporate bonds	19.5	0.2	—	19.7
Total	$88.0	$0.4	$—	$88.4

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Investments in available-for-sale securities at December 31, 2011 were as follows:

Available-for-sale securities	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(Dollars in millions)		
Current:				
Federal government securities	$3.3	$—	$—	$3.3
U.S. corporate bonds	3.9	—	—	3.9
Noncurrent:				
Marketable equity securities	67.9	—	(10.9)	57.0
Federal government securities	11.3	0.2	—	11.5
U.S. corporate bonds	7.7	0.1	—	7.8
Total	$94.1	$0.3	$(10.9)	$83.5

Contractual maturities for available-for-sale investments in debt securities at December 31, 2012 were as shown below. Expected maturities will differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

Contractual maturities for available-for-sale securities	Cost	Fair Value
	(Dollars in millions)	
Due in one year or less	$4.1	$4.1
Due in one to five years	51.5	51.9
Total	$55.6	$56.0

The Company’s investments in marketable equity securities consist of an investment in Winsway Coking Coal Holdings Limited (Winsway).

Proceeds from sales of securities amounted to $17.2 million and $52.8 million for the years ended December 31, 2012 and 2011, respectively and realized gains on the sales amounted to $0.1 million and $1.6 million for the years ended December 31, 2012 and 2011, respectively, associated with those sales and maturities.

In addition to the securities described above, the Company previously held an investment in debt and equity securities related to the Company's pro-rata share of funding in the Newcastle Coal Infrastructure Group (NCIG), which was included in "Investments and other assets" in the consolidated balance sheets. These debt securities were recorded at cost, which approximated fair value, and were denominated in U.S. dollars. During the year ended December 31, 2012, the Company received proceeds from the sale of NCIG debt securities of $29.2 million and recognized a loss on the sale of $0.2 million. There were no NCIG securities held at December 31, 2012.

At December 31, 2012, the Company performed its quarterly evaluation of debt and equity securities to determine if any unrealized losses were other than temporary. After evaluating Winsway's credit downgrade, which occurred during the fourth quarter of 2012, and the duration and severity of the market losses incurred to-date, the Company concluded that Winsway's common stock is other-than-temporarily impaired and, as such, recognized a $35.5 million impairment loss on that investment. The market-based fair value of the investment as of December 31, 2012 is the investment's new cost basis. The Company will continue to evaluate its investments in debt and equity securities for impairment that is other than temporary at each reporting date.

In November 2012, the Company purchased $4.8 million of time deposits denominated in Chinese Renminbi with six month maturities. These investments are classified as held-to-maturity investments which are recorded at amortized cost and are included in "Other current assets" in the consolidated balance sheets at December 31, 2012. The Company had no held-to-maturity securities at December 31, 2011.

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(7) Derivatives and Fair Value Measurements

Risk Management — Non Coal Trading Activities

The Company is exposed to various types of risk in the normal course of business, including foreign currency exchange rate risk for non-U.S. dollar expenditures, price risk on commodities utilized in the Company's mining operations and interest rate risk on long-term debt. The Company predominantly manages commodity price risk (excluding coal trading activities) related to the sale of coal through the use of long-term, fixed-price contracts, rather than through the use of derivative instruments. In order to manage its exposure related to price risk on certain commodities used in production, as well as for foreign currency exchange rate and interest rate risk, the Company utilizes derivative financial instruments. These risks are actively monitored in an effort to ensure compliance with the risk management policies of the Company.

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

Diesel Fuel and Explosives Hedges. The Company is exposed to commodity price risk associated with diesel fuel and explosives utilized in production in the U.S. and Australia. This risk is managed through the use of derivatives, primarily swaps, and cost pass-through contracts. The Company generally designates the swap contracts as cash flow hedges, with the objective of reducing the variability of cash flows associated with forecasted diesel fuel and explosives purchases.

Interest Rate Swaps. The Company is exposed to interest rate risk on its fixed rate and variable rate long-term debt. From time to time, the Company manages the interest rate risk associated with the fair value of its fixed rate borrowings using fixed-to-floating interest rate swaps to effectively convert a portion of the underlying cash flows on the debt into variable rate cash flows. The Company designates these swaps as fair value hedges, with the objective of hedging against adverse changes in the fair value of the fixed rate debt that results from market interest rate changes. In addition, from time to time, interest rate risk associated with the Company’s variable rate borrowings is managed using floating-to-fixed interest rate swaps. The Company designates these swaps as cash flow hedges, with the objective of reducing the variability of cash flows associated with market interest rate changes. As of December 31, 2012, the Company had no interest rate swaps in place.

Notional Amounts and Fair Value. The following summarizes the Company’s foreign currency and commodity positions at December 31, 2012:

	Notional Amount by Year of Maturity					
	Total	2013	2014	2015	2016	2017 and thereafter
Foreign Currency						
A$:US$ hedge contracts (A$ millions)	$4,448.2	$2,173.6	$1,513.5	$761.1	$—	$—
Commodity Contracts						
Diesel fuel hedge contracts (million gallons)	188.3	102.0	63.6	22.7	—	—
U.S. explosives hedge contracts (million MMBtu)	3.8	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)	$4,448.2	$—	$—	$286.9
Commodity Contracts				
Diesel fuel hedge contracts (million gallons)	188.3	—	—	$9.6
U.S. explosives hedge contracts (million MMBtu)	3.8	—	—	$(5.6)

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Hedge Ineffectiveness. The Company assesses, both at inception and at least quarterly thereafter, whether the derivatives used in hedging activities are highly effective at offsetting the changes in the anticipated cash flows of the hedged item. The effective portion of the change in the fair value is recorded in “Accumulated other comprehensive income (loss)” until the hedged transaction impacts reported earnings, at which time any gain or loss is reclassified to earnings. To the extent that periodic changes in the fair value of derivatives deemed highly effective exceeds such changes in the hedged item, the ineffective portion of the periodic non-cash changes are recorded in earnings in the period of the change. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes changes in the fair value of the instrument in earnings in the period of the change.

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

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

The Company’s derivative positions for the hedging of forecasted foreign currency expenditures contain a small measure of ineffectiveness due to timing differences between the hedge settlement and the purchase transaction, which could differ by less than a day and up to a maximum of 30 days.

The tables below show the classification and amounts of pre-tax gains and losses related to the Company’s non-trading hedges during the years ended December 31, 2012, 2011 and 2010:

		Year Ended December 31, 2012			
Financial Instrument	Statement of Operations Classification Gains (Losses) - Realized	Gain recognized in income on non-designated derivatives	Gain recognized in other comprehensive income on derivative (effective portion)	Gain reclassified from other comprehensive income into income (effective portion)	Loss reclassified from other comprehensive income into income (ineffective portion)
		(Dollars in millions)			
Commodity swaps and options	Operating costs and expenses	$—	$ 14.5	$48.3	$ (4.7)
Foreign currency cash flow hedge contracts	Operating costs and expenses	—	148.0	351.7	—
Total		$—	$ 162.5	$400.0	$ (4.7)

		Year Ended December 31, 2011			
Financial Instrument	Statement of Operations Classification Gains (Losses) - Realized	Loss recognized in income on non-designated derivatives[(1)]	Gain (loss) recognized in other comprehensive income on derivative (effective portion)	Gain reclassified from other comprehensive income into income (effective portion)	Gain reclassified from other comprehensive income into income (ineffective portion)
		(Dollars in millions)			

Commodity swaps and options	Operating costs and expenses	$—	$ 30.7	$42.7	$ 4.8
Foreign currency cash flow hedge contracts					
- Operating costs	Operating costs and expenses	—	193.4	342.2	—
- Capital expenditures	Depreciation, depletion and amortization	—	(0.5)	—	—
Foreign currency economic hedge contracts	Acquisition costs related to PEA-PCI	(32.8)	—	—	—
Total		$(32.8)	$ 223.6	$384.9	$ 4.8

(1) Relates to foreign currency contracts associated with the acquisition of PEA-PCI shares under the takeover process.

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Financial Instrument	Statement of Operations Classification Gains (Losses) - Realized	Year Ended December 31, 2010 Loss recognized in income on non-designated derivatives[2]	Gain recognized in other comprehensive income on derivative (effective portion)	Gain (loss) reclassified from other comprehensive income into income (effective portion)	Loss reclassified from other comprehensive income into income (ineffective portion)
		(Dollars in millions)			
Interest rate swaps cash flow hedge contracts	Interest expense	$(8.5)	$ 0.8	$(0.5)	$ —
Commodity swaps and options	Operating costs and expenses	—	29.9	(36.2)	(1.1)
Foreign currency cash flow hedge contracts	Operating costs and expenses	—	622.2	188.2	—
Total		$(8.5)	$ 652.9	$151.5	$ (1.1)

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

In November 2012, with the Australian dollar trading at elevated levels against the U.S. dollar, the Company terminated certain of its Australian dollar forward contracts in exchange for aggregate realized cash proceeds of $151.8 million. Prior to discontinuation, those contracts comprised an aggregate notional amount of A$1.9 billion originally contracted for settlement during 2014 and 2015 and were designated as cash flow hedges of Australian dollar expenditures forecasted to occur at those times. Upon termination, the Company executed at-market Australian dollar forward contracts with notional amounts and forward settlement dates identical to the terminated contracts and designated those replacement contracts as cash flow hedges of the anticipated future Australian dollar expenditures previously hedged by the terminated contracts. Because those forecasted expenditures remained probable of occurring as of December 31, 2012, the Company continued to reflect the effective portion of the realized gains on the terminated forward contracts in "Accumulated other comprehensive income" at that date and expects to reclassify those gains to earnings in conjunction with the occurrence of the related hedged expenditures during 2014 and 2015.

The classification and amount of derivatives presented before netting by counterparty on a gross basis as of December 31, 2012 and 2011 are as follows:

Financial Instrument	Fair Value as of December 31, 2012 Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
	(Dollars in millions)			
Commodity swaps and options	$18.3	$2.5	$8.5	$8.3
Foreign currency cash flow hedge contracts	260.1	27.6	—	0.8
Total	$278.4	$30.1	$8.5	$9.1

Financial Instrument	Fair Value as of December 31, 2011 Current Assets	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities
	(Dollars in millions)			
Commodity swaps and options	43.4	11.7	7.1	15.0

Foreign currency cash flow hedge contracts	270.4	229.0	4.3	4.5
Total	$313.8	$240.7	$11.4	$19.5

Based on the net fair value of the Company’s non-coal trading positions held in “Accumulated other comprehensive income” at December 31, 2012, unrealized gains to be reclassified from comprehensive income to earnings over the next 12 months associated with the Company’s foreign currency and diesel fuel hedge programs are expected to be approximately $260 million and $14 million, respectively. The unrealized losses to be realized under the explosives hedge program are expected to be approximately $4 million. As these unrealized gains and losses are associated with derivative instruments that represent hedges of forecasted transactions, the amounts reclassified to earnings will partially offset the realized transactions.

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

See Note 8. "Coal Trading" for information related to the Company’s coal trading activities.

Fair Value Measurements

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

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

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
		(Dollars in millions)		
Investment in available-for-sale debt and equity securities	$75.4	$13.0	$—	$88.4
Commodity swaps and options	—	4.0	—	4.0
Foreign currency cash flow hedge contracts	—	286.9	—	286.9
Total net financial assets	$75.4	$303.9	$—	$379.3

	December 31, 2011			
	Level 1 (1)	Level 2 (1)	Level 3	Total
		(Dollars in millions)		
Investment in available-for-sale debt and equity securities	$78.0	$5.5	$—	$83.5
Commodity swaps and options	—	33.0	—	33.0
Foreign currency cash flow hedge contracts	—	490.6	—	490.6
Total net financial assets	$78.0	$529.1	$—	$607.1

(1) Certain amounts have been revised from a Level 1 to a Level 2 fair value hierarchy classification to conform to the current year presentation, which had no effect on previously reported consolidated results and was not material to the footnotes to the consolidated financial statements.

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including interest rate yield curves, exchange indices, broker quotes, published indices and other market quotes. Below is a summary of the Company’s valuation techniques for Level 1 and 2 financial assets and liabilities:

- Investments in debt and equity securities: corporate bonds and U.S. government treasury instruments are valued based on quoted prices in active markets (Level 1) and U.S. government agency securities are valued based on derived prices in active markets (Level 2).
- Commodity swap contracts — diesel fuel and explosives: valued based on a valuation that is corroborated by the use of market-based pricing (Level 2).
- Foreign currency forward and option contracts: valued utilizing inputs obtained in quoted public markets (Level 2).

The Company did not have any transfers between levels during the years ended December 31, 2012, 2011 or 2010 for its non-coal trading positions. The Company’s policy is to value all transfers between levels using the beginning of period valuation.

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Other Financial Instruments. The following methods and assumptions were used by the Company in estimating fair values for other financial instruments as of December 31, 2012 and 2011:

- Cash and cash equivalents, accounts receivable, including those within the Company's accounts receivable securitization program, and accounts payable and accrued expenses have carrying values which approximate fair value due to the short maturity or the liquid nature of these instruments.
- Held-to-maturity investments in time deposits denominated in Chinese Renminbi of $4.8 million have carrying values based on amortized cost which approximates fair value due to the short maturity of these investments.
- Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available (Level 2), and otherwise on estimated borrowing rates to discount the cash flows to their present value (Level 3). The carrying amounts of the 7.875% Senior Notes due December 2026 and the Convertible Junior Subordinated Debentures due 2066 (the Debentures) are net of the respective unamortized note discounts.

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

	December 31, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		(Dollars in millions)		
Long-term debt	$6,252.9	$6,583.9	$6,657.5	$6,922.7

Nonperformance and Credit Risk

The fair value of the Company's non-coal trading derivative assets and liabilities reflects adjustments for nonperformance and credit risk. The Company manages its counterparty risk through established credit standards, diversification of counterparties, utilization of investment grade commercial banks and continuous monitoring of counterparty creditworthiness. To reduce its credit exposure for these hedging activities, the Company seeks to enter into netting agreements with counterparties that permit the Company to offset asset and liability positions with such counterparties in the event of default.

(8) Coal Trading

Risk Management

The Company engages in direct and brokered trading of coal and freight-related contracts in over-the-counter markets (coal trading), some of which is subsequently exchange-cleared and some of which is bilaterally settled. Except those for which the Company has elected to apply a normal purchases and normal sales exception, all derivative coal trading contracts are accounted for at fair value.

The Company's policy is to include instruments associated with coal trading transactions as a part of its trading book. Trading revenues from such transactions are recorded in "Other revenues" in the consolidated statements of operations and include realized and unrealized gains and losses on derivative instruments, including coal deliveries related to contracts accounted for under the normal purchases and normal sales exception. Therefore, the Company has elected the trading exemption surrounding disclosures related to its coal trading activities.

Trading revenues recognized during the years ended December 31, 2012, 2011 and 2010 were as follows:

	Year Ended December 31,		
Trading Revenue by Type of Instrument	2012	2011	2010
	(Dollars in millions)		
Commodity swaps and options	$159.9	$(41.4)	$23.2
Physical commodity purchase/sale contracts	(8.1)	187.0	135.5
Total trading revenue	$151.8	$145.6	$158.7

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Risk Management

Hedge Ineffectiveness. The Company assesses, both at inception and at least quarterly thereafter, whether the derivatives used in hedging activities are highly effective at offsetting the changes in the anticipated cash flows of the hedged item. The effective portion of the change in the fair value is recorded in "Accumulated other comprehensive income (loss)" until the hedged transaction impacts reported earnings, at which time gains and losses are also reclassified to earnings. To the extent that periodic changes in the fair value of a derivative exceeds the changes in the hedged item to which it has been designated, the ineffective portion is recorded in earnings in the period of the change. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes the changes in fair value of the instrument in earnings in the period of the change.

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

Forecasted Transactions No Longer Probable. During 2012, the Company reclassified gains of $7.5 million out of "Accumulated other comprehensive income (loss)" to earnings as the underlying forecasted transactions were deemed no longer probable of occurring. Approximately $4.5 million of that amount relates to disruptions to forecasted transactions due to the bankruptcy declaration of a counterparty to certain of the Company's physical purchase contracts, which occurred in the third quarter of 2012.

Fair Value Measurements

The Company's trading assets and liabilities are generally comprised of forward contracts, financial swaps and cash margin. The fair value of assets and liabilities from coal trading activities is set forth below:

	December 31,			
	2012		2011	
	Gross Basis	Net Basis	Gross Basis	Net Basis
	(Dollars in millions)			
Assets from coal trading activities	$380.4	$52.4	$170.4	$44.6
Liabilities from coal trading activities	(190.5)	(19.4)	(84.0)	(10.3)
Subtotal	189.9	33.0	86.4	34.3
Net variation margin held [(1)]	(156.9)	—	(52.1)	—
Net fair value of coal trading positions	$33.0	$33.0	$34.3	$34.3

(1) Represents margin held from exchanges and counterparties to over-the-counter derivative contracts of $156.9 million and $52.1 million at December 31, 2012 and 2011, respectively. Approximately $76 million and $23 million of the margin held at December 31, 2012 and 2011, respectively, related to cash flow hedges.

The fair value of coal trading positions designated as cash flow hedges of forecasted sales, before the application of margin, was an asset of $153.1 million and $22.4 million as of December 31, 2012 and 2011, respectively. The increase in the fair value of those positions was predominantly driven by a decrease in the associated price levels of hedged international thermal coal products during 2012.

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

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Commodity swaps and options	$1.2	$24.4	$—	$25.6

Physical commodity purchase/sale contracts	—	2.2	5.2	7.4
Total net financial assets	$1.2	$26.6	$5.2	$33.0

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	December 31, 2011			
	Level 1	Level 2	Level 3	Total
		(Dollars in millions)		
Commodity swaps and options	$21.2	$(1.9)	$—	$19.3
Physical commodity purchase/sale contracts	—	6.3	8.7	15.0
Total net financial assets	$21.2	$4.4	$8.7	$34.3

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including U.S. interest rate curves, LIBOR yield curves, Chicago Mercantile Exchange (CME), Intercontinental Exchange indices (ICE), NOS Clearing ASA, LCH.Clearnet (formerly known as the London Clearing House), Singapore Exchange (SGX), broker quotes, published indices and other market quotes. Below is a summary of the Company’s valuation techniques for Level 1 and 2 financial assets and liabilities:

- Commodity swaps and options: generally valued based on unadjusted quoted prices in active markets (Level 1) or a valuation that is corroborated by the use of market-based pricing (Level 2).
- Physical commodity purchase/sale contracts: purchases and sales at locations with significant market activity corroborated by market-based information (Level 2).

Physical commodity purchase/sale contracts transacted in less liquid markets or contracts, such as long-term arrangements with limited price availability, are classified in Level 3. Indicators of less liquid markets are those with periods of low trade activity or wide pricing spreads between broker quotes.

The Company's risk management function, which is independent of the Company's commercial trading function, is responsible for valuation policies and procedures, with oversight from executive management. Generally, the Company's Level 3 instruments or contracts are valued using bid/ask price quotations and other market assessments obtained from multiple, independent third-party brokers or other transactional data incorporated into internally-generated discounted cash flow models. While the Company does not anticipate any decrease in the number of third-party brokers or market liquidity, the occurrence of such events could erode the quality of market information and therefore the valuation of its market positions. The Company's valuation techniques include basis adjustments to the foregoing price inputs for quality (such as heat rate and sulfur and ash content) and credit and nonperformance risk. The Company's risk management function independently validates the Company's valuation inputs, including unobservable inputs, with third-party information and settlement prices from other sources where available. A daily process is performed to analyze market price changes and changes to the portfolio. Further periodic validation occurs at the time contracts are settled with the counterparty. These valuation techniques have been consistently applied in all periods presented, and the Company believes it has obtained the most accurate information available for the types of derivative contracts held.

The following table summarizes the quantitative unobservable inputs utilized by the Company's internally-developed valuation models for physical commodity purchase/sale contracts classified as Level 3 as of December 31, 2012:

	Range		Weighted
Input	Low	High	Average
Quality adjustments	2%	22%	14%
Non-performance adjustments	4%	4%	4%

Significant increases or decreases in the inputs in isolation could result in a significantly higher or lower fair value measurement. The unobservable inputs do not have a direct interrelationship; therefore, a change in one unobservable input would not necessarily correspond with a change in another unobservable input.

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

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Beginning of year	$8.7	$18.6	$17.0
Total gains (losses) realized/unrealized:			
Included in earnings	17.5	8.9	2.1
Included in other comprehensive income	—	—	(0.5)
Settlements	(21.0)	(2.1)	(0.1)
Transfers in	—	1.0	—
Transfers out	—	(17.7)	0.1
End of year	$5.2	$8.7	$18.6

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

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Changes in unrealized gains [(1)]	$4.1	$8.7	$6.7

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

The Company did not have any significant transfers between Level 1 and Level 2 during 2012, 2011 or 2010. Certain of the Company’s physical commodity purchase/sale contracts were transferred from Level 3 to Level 2 in 2011 as the settlement dates entered a more liquid market. The Company’s policy is to value all transfers between levels using the beginning of period valuation.

Based on the net fair value of the Company’s coal trading positions held in “Accumulated other comprehensive income (loss)” at December 31, 2012, the Company expects to reclassify unrealized gains of approximately $132 million from comprehensive income to earnings over the next 12 months. As these unrealized losses are associated with derivative instruments that represent hedges of forecasted transactions, the amounts reclassified to earnings may partially offset the impacts of the underlying realized transactions in the consolidated statements of operations.

As of December 31, 2012, the timing of the estimated future realization of the value of the Company’s trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio Total
2013	77%
2014	15%
2015	6%
2016	2%
	100%

Nonperformance and Credit Risk

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

At December 31, 2012, 66% of the Company’s credit exposure related to coal trading activities with investment grade counterparties while 19% was with non-investment grade counterparties and 15% was with counterparties that are not rated.

Performance Assurances and Collateral

Certain of the Company’s derivative trading instruments require the parties to provide additional performance assurances whenever a material adverse event jeopardizes one party’s ability to perform under the instrument. If the Company was to sustain a material adverse event (using commercially reasonable standards), the counterparties could request collateralization on derivative trading instruments in net liability positions which, based on an aggregate fair value at December 31, 2012 and 2011, would have amounted to collateral postings of approximately $8 million and $11 million, respectively, to its counterparties. As of December 31, 2012 and 2011, no collateral was posted to counterparties for such positions.

Certain of the Company’s other derivative trading instruments require the parties to provide additional performance assurances whenever a credit downgrade occurs below a certain level as specified in each underlying contract. The terms of such derivative trading instruments typically require additional collateralization, which is commensurate with the severity of the credit downgrade. If a credit downgrade were to have occurred below contractually specified levels, the Company’s additional collateral requirement owed to its counterparties would have been zero at December 31, 2012 and 2011 based on the aggregate fair value of all derivative trading instruments with such features that are in a net liability position. As such, the Company had no posting requirements for such instruments as of December 31, 2012 and 2011.

The Company is required to post collateral on positions that are in a net liability position and is entitled to receive collateral on positions that are in a net asset position with an exchange and certain of its over-the-counter derivative contract counterparties. This collateral is known as variation margin. At December 31, 2012 and 2011, the Company held net variation margin of $156.9 million and $52.1 million, respectively. The variation margin held at December 31, 2012 and 2011 is reflected in "Assets from coal trading activities, net" in the consolidated balance sheets.

In addition to the requirements surrounding variation margin, the Company is required by the exchange upon which it transacts to post certain additional collateral known as initial margin, which represents an estimate of potential future adverse price movements across the Company’s portfolio under normal market conditions. As of December 31, 2012 and 2011, the Company had posted initial margin of $23.2 million and $34.0 million, respectively, which is reflected in “Other current assets” in the consolidated balance sheets. The Company also posted $0.5 million of margin in excess

of the exchange-required variation and initial margin discussed above as of December 31, 2012, which is also reflected in “Other current assets" in the consolidated balance sheet for that period.
MF Global UK Limited
In October 2011, MF Global UK Limited (MF Global UK), a United Kingdom (U.K.) based broker-dealer, was placed into the U.K.'s administration process (a process similar to bankruptcy proceedings in the U.S.) by the Financial Services Authority following the Chapter 11 bankruptcy filing of its U.S. parent, MF Global Holdings Ltd. The Company had used MF Global UK to broker certain of its coal trading transactions. During 2012, the Company received $20.0 million of the initial outstanding amount of $52.1 million that was held with MF Global UK when it was placed into the U.K.'s administration process and sold its remaining claim with the special administrators to a third party on a discounted basis for $28.0 million. As a result of that sale, the Company recognized a loss of $4.1 million during the year ended December 31, 2012.

(9) Financing Receivables

The Company had total financing receivables of $391.7 million and $376.1 million at December 31, 2012 and 2011, respectively, which consisted of the following:

Balance Sheet Classification	December 31, 2012	December 31, 2011
	(Dollars in millions)	
Accounts receivable, net	$0.7	$51.3
Other current assets	—	65.0
Investments and other assets	391.0	259.8
Total financing receivables	$391.7	$376.1

The Company periodically assesses the collectability of accounts and loans receivable by considering factors such as specific evaluation of collectability, historical collection experience, the age of the receivable and other available evidence. Below is a description of the Company's financing receivables at December 31, 2012.

Codrilla Mine Project. In 2011, a wholly owned subsidiary of PEA-PCI, then Macarthur Coal Limited, completed the sale of its 85% interest in the Codrilla Mine Project to participants of the Coppabella Moorvale Joint Venture (CMJV) where PEA-PCI sold down its interest in the Codrilla project to the CMJV (Codrilla sell down) so that, following completion of the sale, ownership of the Codrilla Mine Project reflected the existing ownership of the Coppabella and Moorvale mines with PEA-PCI retaining a 73.3% ownership. Prior to the acquisition of PEA-PCI by the Company, consideration of $15 million Australian dollars was received by PEA-PCI upon completion of the Codrilla sell down, representing 20% of the agreed price. Two installments, for which the Company holds non-interest-bearing receivables, are due upon the completion of certain milestones. The first installment, with 40% due on the granting of the related mining lease, was received during the three months ended September 30, 2012. The final 40% is due upon the mine's first coal shipment. At December 31, 2011, the first installment of $34.2 million was included in "Accounts receivable, net" in the consolidated balance sheet which was collected from CMJV participants in the third quarter 2012 when the mining lease was granted and is reflected in "Proceeds from disposal of assets, net of notes receivable" in the consolidated statements of cash flows for the year ended December 31, 2012. There are currently no indications of impairment on the remaining installment and the Company expects to receive full payment upon the mine's first shipment. The remaining balance associated with these receivables is recorded in "Investments and other assets" which was $33.6 million and $35.6 million at December 31, 2012 and 2011, respectively, in the consolidated balance sheets.

Middlemount Mine. The Company periodically makes loans to the Middlemount Mine joint venture (Middlemount) for purposes of funding capital expenditures and working capital requirements, pursuant to the related shareholders' agreement. Middlemount intends to pay down the loans as excess cash is generated as required by the shareholders' agreement. The loans bear interest at a rate equal to the monthly average 30-day Australian Bank Bill Swap Reference Rate plus 3.5%. The Company reviewed the loans for collectability and, as of December 31, 2012, expects to receive full payment of amounts due. "Other current assets" included $65.0 million at December 31, 2011, which was reclassified to "Investments and other assets" during the year ended December 31, 2012. "Investments and other assets" included $357.4 million and $224.2 million at December 31, 2012 and 2011, respectively, in the consolidated balance sheets related to these loans.

Other Financing Receivables. From time to time, the Company may enter into transactions resulting in accounts or notes receivable held by the Company, which have been reflected in "Accounts receivable, net." These notes are generally short term in nature with positive historical collection experience and do not represent a material credit risk to the Company. During 2012, the Company collected all such receivables outstanding as of December 31, 2011.

(10) Income Taxes

(Loss) income from continuing operations before income taxes consisted of the following:

	Year Ended December 31, 2012	2011	2010
	(Dollars in millions)		
U.S.	$1,049.1	$818.0	$532.2
Non-U.S.	(1,257.7)	558.0	606.5
Total	$(208.6)	$1,376.0	$1,138.7

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Total income tax provision consisted of the following:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Current:			
U.S. federal	$116.8	$103.4	$113.9
Non-U.S.	127.6	58.9	78.8
State	12.2	12.2	1.0
Total current	256.6	174.5	193.7
Deferred:			
U.S. federal	(32.7)	138.0	46.3
Non-U.S.	28.8	42.8	68.1
State	9.6	7.9	5.6
Total deferred	5.7	188.7	120.0
Total provision	$262.3	$363.2	$313.7

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

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Expected income tax provision at federal statutory rate	$(73.0)	$480.8	$399.7
Excess depletion	(69.4)	(70.8)	(53.5)
Capital loss	(118.1)	—	—
Minerals resource rent tax, net of federal tax benefit	77.2	—	—
Foreign earnings provision differential	(68.7)	(99.2)	(124.5)
Foreign earnings repatriation	9.1	7.6	84.5
Remeasurement of foreign income tax accounts	7.9	(0.9)	47.9
State income taxes, net of federal tax benefit	(1.1)	12.3	(4.8)
General business tax credits	(17.4)	(17.8)	(17.0)
Changes in valuation allowance	521.5	15.4	(28.7)
Changes in tax reserves	24.5	14.7	—
Other, net	(30.2)	21.1	10.1
Total provision	$262.3	$363.2	$313.7

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

	December 31, 2012	2011
	(Dollars in millions)	
Deferred tax assets:		
Tax credits and loss carryforwards	$1,390.1	$432.8
Minerals resource rent tax	689.7	—
Postretirement benefit obligations	473.3	485.4
Intangible tax asset and purchased contract rights	7.9	13.4
Accrued reclamation and mine closing liabilities	137.9	112.9
Accrued long-term workers' compensation liabilities	15.7	15.6
Employee benefits	64.7	53.3
Financial guarantees	18.6	18.5
Other	56.5	57.8
Total gross deferred tax assets	2,854.4	1,189.7
Deferred tax liabilities:		
Property, plant, equipment and mine development, leased coal interests and advance royalties, principally due to differences in depreciation, depletion and asset writedowns	1,596.9	1,318.0
Unamortized discount on Convertible Junior Subordinated Debentures	132.8	132.5
Hedge activities	37.5	45.5
Investments and other assets	126.3	109.8
Total gross deferred tax liabilities	1,893.5	1,605.8
Valuation allowance, income tax	(714.9)	(79.8)
Valuation allowance, minerals resource rent tax	(766.9)	—
Net deferred tax liability	$(520.9)	$(495.9)
Deferred taxes are classified as follows:		
Current deferred income taxes	$56.4	$27.3
Noncurrent deferred income taxes	(577.3)	(523.2)
Net deferred tax liability	$(520.9)	$(495.9)

The Company's tax credits and tax effected loss carryforwards includes U.S. alternative minimum tax (AMT) credits of $232.6 million, general business credits of $52.6 million, U.S. capital losses of $113.2 million, state net operating loss (NOL) carryforwards of $36.1 million and foreign NOL carryforwards of $955.6 million as of December 31, 2012. The AMT credits and foreign NOLs have no expiration date. The U.S. capital loss and the general business credits begin to expire in 2017 and 2027, respectively. The state NOLs begin to expire in the year 2013. In assessing the near term use of NOLs and tax credits and corresponding valuation allowance adjustments, the Company evaluated the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. The $521.5 million change in the valuation allowance recorded directly to deferred income tax expense was primarily due to limitations on the U.S. capital losses, a loss utilization factor on certain Australian loss carryforwards which will limit recoverability and foreign deferred tax assets with limited recoverability. The income tax valuation allowance at December 31, 2012 of $714.9 million represents a reserve for U.S. capital losses, state NOLs, foreign NOLs and certain deferred tax assets.

During the year ended December 31, 2012, Australia passed legislation creating a minerals resource rent tax (the MRRT) effective from July 1, 2012. The MRRT is a profits-based tax on the Company's existing and future Australian coal projects at an effective tax rate of 22.5%. Under the MRRT, taxpayers are able to elect a market value asset starting base for existing projects which allows for the fair market value of the tenements to be deducted over the life of the mine as an allowance against MRRT. The realization of the market value allowance is subject to numerous uncertainties including utilization of other MRRT allowances provided under the law and estimates of long-term pricing and cost data. During 2012, the Company recorded a net deferred tax liability relating to MRRT of $77.2 million. As of December 31, 2012, the Company has recorded a gross deferred tax asset of $871.8 million from the market value allowance, royalty credit carryforwards and other adjustments. The gross deferred tax asset is offset by a deferred tax liability of $182.1 million primarily relating to excess book over tax basis in certain exploration properties. The Company separately recorded a valuation allowance of $766.9 million on the market value allowance due to limitations on recoverability.

During the year ended December 31, 2012, the Company realized a net tax benefit of $74.7 million due to restructuring of foreign operations associated with the acquisition of PEA-PCI. The net tax benefit included a U.S. federal and state capital loss benefit of $39.6 million and a foreign tax benefit of $35.1 million due to the tax basis reset required upon the PEA-PCI operations joining the Company's Australian consolidated tax group.

Unrecognized Tax Benefits

The total amount of the net unrecognized tax benefits included in "Other noncurrent liabilities" in the consolidated balance sheets was $119.7 million ($122.8 million gross) at December 31, 2012 and $114.7 million ($119.6 million gross) at December 31, 2011. The amount of the Company's gross unrecognized tax benefits has increased by $3.2 million since January 1, 2012 due to additions for current positions, a reduction from the successful completion of the 2007-2008 Internal Revenue Service (IRS) audit, effective settlement of the 1999-2006 tax years due to favorable resolution of the 2006 IRS appeals decision and the Company's reassessment of its prior year foreign positions associated with intercompany financing transactions. The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate was $119.7 million at December 31, 2012 and $114.7 million at December 31, 2011. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits is as follows (dollars in millions):

	Year Ended December 31,		
	2012	2011	2010
Balance at beginning of period	$119.6	$111.0	$113.2
Additions for current year tax positions	17.4	5.2	3.4
Additions for prior year positions	31.9	3.4	13.8
Reductions for settlements with tax authorities	(46.1)	—	(19.4)
Reductions for expirations of statutes of limitations	—	—	—
Balance at end of period	$122.8	$119.6	$111.0

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in its income tax provision. The Company recognized $21.2 million and $11.4 million of interest and penalties for the years ended December 31, 2012 and 2011, respectively. The Company had $47.2 million and $26.0 million of accrued interest and penalties related to uncertain tax positions at December 31, 2012 and 2011, respectively.

The Company believes during the next twelve months it is reasonably possible for a $65 million decrease in its net unrecognized tax benefits due to potential audit settlements and the expiration of statutes of limitations.

Tax Returns Subject to Examination

The Company's federal income tax returns are under examination by the IRS for the 2009 and 2010 income tax years. The Company's Australian income tax returns for the tax years 2004 through 2010 are under examination by the

Australian Tax Office (ATO). In December 2012, the ATO issued a revised audit issue paper challenging certain financing transactions with a proposed assessment of $82.2 million (tax of $56.6 million plus interest and penalties of $25.6 million). The Company plans to proceed with litigation and will have to make a deposit payment of 50% of the proposed adjustment upon receipt of the ATO's final assessment.

Notwithstanding these audit cycles, the federal and Australian income tax returns for the year 2011 remain potentially subject to examination. The Company's state income tax returns for the tax years 1999 and thereafter remain potentially subject to examination by various state taxing authorities due to NOL carryforwards.

Foreign Earnings

The total amount of undistributed earnings of foreign subsidiaries for which the Company has not provided deferred taxes because such earnings are considered to be indefinitely reinvested outside the U.S. was $0.5 billion and $1.6 billion as of December 31, 2012 and 2011, respectively. Should the Company repatriate all of these earnings, a one-time income tax charge of up to $120.0 million could occur.

Tax Payments

The following table summarizes the Company’s income tax payments:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
U.S. — federal	$63.0	$200.0	$65.0
U.S. — state and local	11.8	13.2	0.4
Non-U.S.	64.1	61.9	83.0
Total income tax payments	$138.9	$275.1	$148.4

(11) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31,	
	2012	2011
	(Dollars in millions)	
Trade accounts payable	$555.0	$735.6
Other accrued expenses	372.1	274.0
Accrued payroll and related benefits	256.8	254.7
Accrued taxes other than income	203.8	210.5
Accrued royalties	82.3	77.8
Accrued interest	47.5	49.7
Accrued health care insurance	21.3	9.3
Workers’ compensation obligations	18.4	17.3
Accrued environmental	10.6	11.6
Commodity and foreign currency hedge contracts	5.8	7.9
Liabilities associated with discontinued operations	33.3	63.9
Total accounts payable and accrued expenses	$1,606.9	$1,712.3

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(12) Debt

The Company's total indebtedness as of December 31, 2012 and 2011 consisted of the following:

	December 31,	
	2012	2011
	(Dollars in millions)	
Term Loan	$418.8	$468.8
2011 Term Loan Facility	912.5	1,000.0
7.375% Senior Notes due November 2016	650.0	650.0
6.00% Senior Notes due November 2018	1,518.8	1,600.0
6.50% Senior Notes due September 2020	650.0	650.0
6.25% Senior Notes due November 2021	1,339.6	1,500.0
7.875% Senior Notes due November 2026	247.4	247.3
Convertible Junior Subordinated Debentures due December 2066	377.4	375.2
Capital lease obligations	104.6	122.8
Other	33.8	43.4
Total	$6,252.9	$6,657.5

Credit Facility

On June 18, 2010, the Company entered into an unsecured credit agreement (the Credit Agreement) which established a $2.0 billion credit facility (the Credit Facility) and replaced the Company's third amended and restated credit agreement dated as of September 15, 2006. The Credit Agreement provides for a $1.5 billion revolving credit facility (the Revolver) and a $500.0 million term loan facility (the Term Loan). The Company has the option to request an increase in the capacity of the Credit Facility, provided the aggregate increase for the Revolver and Term Loan does not exceed $250.0 million, the minimum amount of the increase is $25.0 million and certain other conditions are met under the Credit Agreement. The Revolver also includes a swingline sub-facility under which up to $50.0 million is available for same-day borrowings. The Revolver commitments and the Term Loan under the Credit Facility will mature on June 18, 2015. On November, 16, 2012, the Company amended the Credit Facility to temporarily increase its maximum consolidated leverage coverage ratio covenant through December 31, 2014. In addition, an extra level was added to the interest rate pricing grid for the Credit Facility, which is included in the information presented below. In conjunction with the amendment, the Company capitalized $4.7 million in deferred financing costs, which will be amortized to interest expense over the remaining term of the Credit Facility.

The Revolver replaced the Company's previous $1.8 billion revolving credit facility and the Term Loan replaced the Company's previous term loan facility (the previous term loan had a balance of $490.3 million at the time of replacement). The Company recorded $21.9 million in deferred financing costs related to the Credit Agreement, which are being amortized to interest expense over the five-year term of the Credit Facility. The Company also recorded refinancing charges of $9.3 million in connection with the replacement, which were recorded in "Interest expense" in the 2010 consolidated statement of operations. The $500.0 million of proceeds from the Term Loan was used to repay the balance due on the Company's previous term loan facility.

All borrowings under the Credit Agreement (other than swingline borrowings and borrowings denominated in currencies other than U.S. dollars) bear interest, at the Company's option, at either a "base rate" or a "eurocurrency rate", as defined in the Credit Agreement, plus in each case, a rate adjustment based on the Company's leverage ratio, as defined in the Credit Agreement, ranging from 3.00% to 1.25% per year for borrowings bearing interest at the "base rate" and from 4.00% to 2.25% per year for borrowings bearing interest at the "eurocurrency rate" (such rate added to the "eurocurrency rate," the "Eurocurrency Margin"). Swingline borrowings bear interest at a "BBA LIBOR" rate equal to the rate at which deposits in U.S. dollars for a one month term are offered in the interbank eurodollar market, as determined by the administrative agent, plus the Eurocurrency Margin. Borrowings denominated in currencies other than U.S. dollars will bear interest at the “eurocurrency rate” plus the Eurocurrency Margin.

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

In addition, the Company pays a letter of credit fee calculated at a rate dependent on the Company’s leverage ratio, as defined in the Credit Agreement, ranging from 4.00% to 2.25% per year of the undrawn amount of each letter of credit and a fronting fee equal to 0.125% per year of the face amount of each letter of credit. These fees are payable quarterly in arrears.

The Term Loan is voluntarily prepayable from time to time without any premium or penalty, subject to certain customary reimbursements of the lenders' costs. The Term Loan is subject to quarterly repayment of 1.25% per quarter, which commenced on December 31, 2010, with the final payment of all amounts outstanding (including accrued interest) being due on June 18, 2015. During the fourth quarter of 2012, the Company voluntarily prepaid $25.0 million in aggregate principal amount of the Term Loan, which represented all of the contractual 2013 quarterly repayments.

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

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

As of December 31, 2012, the Company had no borrowings on the Revolver, but had $105.4 million of letters of credit outstanding. The remaining capacity on the Revolver at December 31, 2012 was $1.4 billion.

The interest rate payable on the Revolver and the Term Loan was LIBOR plus 3.00%, or 3.21% at December 31, 2012.

2011 Term Loan Facility

On October 28, 2011, the Company entered into the 2011 Term Loan Facility under which it borrowed $1.0 billion to finance, in part, the acquisition of PEA-PCI. On November, 16, 2012, the Company amended the 2011 Term Loan Facility to temporarily increase its maximum consolidated leverage ratio covenant through December 31, 2014. In addition, an extra level was added to the interest rate pricing grid for the 2011 Term Loan Facility, which is included in the information presented below. In conjunction with the amendment, the Company capitalized $2.2 million in deferred financing costs, which are being amortized to interest expense over the remaining term of the 2011 Term Loan Facility.

Borrowings under the 2011 Term Loan Facility bear interest, at the Company's option, at a rate equal to (i) LIBOR plus an applicable margin or (ii) a base rate (defined as the highest of (a) the Bank of America prime rate, (b) the Federal Funds rate plus 0.50% and (c) one month LIBOR plus 1.00%) plus an applicable margin. The applicable margin depends on the ratio of the Company's consolidated debt to its adjusted consolidated EBITDA, and may range from 1.75% to 3.50% per year for borrowings bearing interest at LIBOR and from 0.75% to 2.50% per year for borrowings bearing interest at the base rate, as defined in the 2011 Term Loan Facility.

The obligations under the 2011 Term Loan Facility are unsecured and are guaranteed by the Company's direct and indirect domestic subsidiaries that guarantee the Credit Facility. The 2011 Term Loan Facility contains covenants, including financial covenants, and events of default substantially the same as those of the Credit Facility.

The 2011 Term Loan Facility is voluntarily prepayable from time to time without premium or penalty, subject to certain customary reimbursements of the lenders’ costs. The 2011 Term Loan Facility is subject to quarterly repayment of 1.25%, which commenced on April 28, 2012, with the final payment of all amounts outstanding due October 28, 2016. During the fourth quarter of 2012, the Company voluntarily prepaid $50.0 million in aggregate principal amount of the 2011 Term Loan Facility, which represented all of the contractual 2013 quarterly repayments.

As of December 31, 2012, the Company had $912.5 million outstanding under the 2011 Term Loan Facility with an interest rate payable of LIBOR plus 2.5%, or 2.71%.

6.00%, 6.25%, 6.50%, 7.375% and 7.875% Senior Notes (collectively the Senior Notes)

The Senior Notes are senior unsecured obligations and rank senior in right of payment to any subordinated indebtedness; equally in right of payment with any senior indebtedness; are effectively junior in right of payment to the Company's future secured indebtedness, to the extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of its subsidiaries that do not guarantee the notes.

The Senior Notes are jointly and severally guaranteed by nearly all of the Company's domestic subsidiaries, as defined in the note indentures. The note indentures contain covenants that, among other things, limit the Company's ability to create liens and enter into sale and lease-back transactions. The Senior Notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole premium and any accrued unpaid interest to the redemption date. If the Company experiences specific kinds of changes in control and the credit rating assigned to the Senior Notes declines below specified levels within 90 days of that time, holders of such notes have the right to require the Company to repurchase their notes at a repurchase price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to the date of repurchase.

Interest payments on the Senior Notes are scheduled to occur each year as follows:

Senior Notes	Interest Payment Dates
6.00% Senior Notes	May 15 and November 15
6.25% Senior Notes	May 15 and November 15
6.50% Senior Notes	March 15 and September 15
7.375% Senior Notes	May 1 and November 1
7.875% Senior Notes	May 1 and November 1

On November 15, 2011, the Company completed a $1.6 billion offering of 6.00% Senior Notes due November 2018 (the 6.00% Senior Notes) and a $1.5 billion offering of 6.25% Senior Notes due November 2021 (the 6.25% Senior Notes), with the proceeds of the offering used, in part, to finance the acquisition of Macarthur. On the same date, the Company, 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). During the second quarter of 2012, the Company repurchased $81.2 million and $160.4 million in aggregate principal amount of its 6.00% and 6.25% Senior Notes due 2018 and 2021, respectively, with existing cash on hand. The Company recognized a loss on debt extinguishment of $2.8 million associated with these repurchases, which was comprised of $3.4 million of expense related to the write-off of deferred financing costs and a gain of $0.6 million as the repurchases were made below par value. The loss is classified in "Interest expense" in the consolidated statement of operations for the year ended December 31, 2012. In the third quarter of 2012, the Company commenced an offer to exchange any and all of its 6.00% and 6.25% Senior Notes outstanding for substantially identical freely tradable debt securities registered under the Securities Act of 1933. The exchange offer was completed in October 2012 and did not affect the Company's indebtedness outstanding.

On August 25, 2010, the Company completed a $650.0 million offering of 6.50% Senior Notes due September 2020 (the 6.50% Senior Notes). The Company used the net proceeds of $641.9 million from the issuance of the 6.50% Senior Notes, after deducting underwriting discounts and expenses, and cash on hand to extinguish its previously outstanding $650.0 million aggregate principal 6.875% Senior Notes formerly due in March 2013 (the 2013 Notes). All of the 2013 Notes were either tendered or redeemed during 2011. The Company recognized debt extinguishment costs of $8.4 million, which was recorded in "Interest expense" in the consolidated statements of operations. The issuance of the 6.50% Senior Notes and the extinguishment of the 2013 Notes allowed the Company to extend the maturity of its senior indebtedness and lower the coupon rate.

5.875% Senior Notes

On April 15, 2011, the Company used cash on hand to redeem its 5.875% Senior Notes due in April 2016 (the 5.875% Senior Notes) in the aggregate principal amount of $218.1 million. In compliance with the terms of the indenture governing the 5.875% Senior Notes, the redemption price was equal to 100.979% of the aggregate principal amount of the 5.875% Senior Notes plus accrued and unpaid interest to April 15, 2011. The Company recognized costs of $1.7 million associated with the redemption.

Convertible Junior Subordinated Debentures

As of December 31, 2012, the Company had $732.5 million aggregate principal outstanding of Debentures that generally require interest to be paid semiannually at a rate of 4.75% per year. The Company may elect to, and to the extent that a mandatory trigger event (as defined in the indenture governing the Debentures) has occurred and is continuing will be required to, defer interest payments on the Debentures. After five years of deferral at the Company's option, or upon the occurrence of a mandatory trigger event, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay deferred interest, subject to certain limitations. In no event may the Company defer payments of interest on the Debentures for more than 10 years.

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) the Company's closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $81.13 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of the Company's common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 17. "Stockholders' Equity") with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with the Company's common stock. As a result of the Patriot Coal Corporation (Patriot) spin-off, the conversion rate was adjusted. The conversion rate has also been adjusted when there has been a change in the Company's dividend distribution rate. The current conversion rate is 17.2563 shares of common stock per $1,000 principal amount of Debentures effective February 6, 2013. This adjusted conversion rate represents a conversion price of $57.95.

Between December 20, 2011 and December 19, 2036, the Company may redeem the Debentures, in whole or in part, if for at least 20 out of the 30 consecutive trading days immediately prior to the date on which notice of redemption is given, the Company's closing common stock price has exceeded 130% of the then applicable conversion price for the Debentures (currently $75.34 per share). On or after December 20, 2036, whether or not the redemption condition is satisfied, the Company may redeem the Debentures, in whole or in part. The Company may not redeem any Debentures unless (i) all accrued and unpaid interest on the Debentures has been paid in full on or prior to the redemption date and (ii) if any perpetual preferred stock is outstanding, the Company has first given notice to redeem the perpetual preferred stock in the same proportion as the redemption of the Debentures. Any redemption of the Debentures will be at a cash redemption price of 100% of the principal amount of the Debentures to be redeemed, plus accrued and unpaid interest to the date of redemption.

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

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

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

The Company accounts for the liability and equity components of the Debentures in a manner that reflects the nonconvertible debt borrowing rate when recognizing interest cost in subsequent periods. The following table illustrates the carrying amount of the equity and debt components of the Debentures:

	December 31,	
	2012	2011
	(Dollars in millions)	
Carrying amount of the equity component	$215.4	$215.4
Principal amount of the liability component	$732.5	$732.5
Unamortized discount	(355.1)	(357.3)
Net carrying amount	$377.4	$375.2

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

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Effective interest rate	4.9%	4.9%	4.9%
Interest expense — contractual interest coupon	$34.8	$34.8	$34.8
Interest expense — amortization of debt discount	2.1	1.8	1.6

The remaining period over which the discount will be amortized is 29 years as of December 31, 2012.

Capital Lease Obligations

The Company's capital lease obligations pertain to the financing of mining equipment used in operations. Refer to Note 13. "Leases" for additional information associated with the Company's capital leases.

Debt Maturities, Interest Paid and Financing Costs

The aggregate amounts of long-term debt maturities (including unamortized debt discounts) subsequent to December 31, 2012, including capital lease obligations, were as follows:

Year of Maturity	(Dollars in millions)
2013	$47.8
2014	111.2
2015	461.6
2016	1,477.9
2017	9.3
2018 and thereafter	4,145.1
Total	$6,252.9

Interest paid on long-term debt was $396.1 million, $205.3 million and $197.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Financing costs incurred with the issuance of the Company’s debt are being amortized to interest expense over the remaining term of the associated debt. The remaining balance at December 31, 2012 was $78.6 million, of which $62.7 million will be amortized to interest expense over the next five years.

(13) Leases

The Company leases equipment and facilities under various noncancelable lease agreements. Certain lease agreements require the maintenance of specified ratios and are subject to the restrictive covenants of the Company's credit facilities. Rental expense under operating leases was $247.5 million, $170.6 million and $129.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. The gross value of property, plant, and equipment under capital leases was $162.5 million as of December 31, 2012 and $177.2 million as of December 31, 2011, related primarily to the leasing of mining equipment. The accumulated depreciation for these items was $83.3 million and $46.6 million at December 31, 2012 and 2011, respectively, and changes thereto have been included in "Depreciation, depletion and amortization" in the consolidated statements of operations.

The Company also leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $637.5 million, $610.6 million and $540.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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

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

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Future minimum lease and royalty payments as of December 31, 2012 are as follows:

Year Ending December 31,	Capital Leases	Operating Leases	Coal Lease and Royalty Obligations
	(Dollars in millions)		
2013	$42.2	$145.1	$282.2
2014	26.6	130.5	280.4
2015	11.2	115.1	278.0
2016	11.1	102.3	252.6
2017	10.9	81.6	4.6
2018 and thereafter	23.4	102.9	28.3
Total minimum lease payments	125.4	$677.5	$1,126.1
Less interest	20.8		
Present value of minimum capital lease payments	$104.6		

As of December 31, 2012, certain of the Company's lease obligations were secured by outstanding surety bonds totaling $105.3 million.

(14) Asset Retirement Obligations

Reconciliations of the Company's asset retirement obligations are as follows:

	December 31, 2012	2011
	(Dollars in millions)	
Balance at beginning of year	$615.2	$484.9
Liabilities incurred or acquired	13.6	43.0
Liabilities settled or disposed	(12.8)	(8.7)
Accretion expense	34.3	28.3
Revisions to estimates	37.2	67.7
Balance at end of year	$687.5	$615.2
Balance at end of year — active locations	$629.1	$567.9
Balance at end of year — closed or inactive locations	$58.4	$47.3

The credit-adjusted, risk-free interest rates were 6.28%, 5.76%, and 6.37% at December 31, 2012, 2011 and 2010, respectively.

As of December 31, 2012 and 2011, the Company had $571.6 million and $791.6 million, respectively, in surety bonds and bank guarantees outstanding to secure reclamation obligations or activities. The amount of reclamation self-bonding in certain states in which the Company qualifies was $1,275.8 million and $929.6 million as of December 31, 2012 and 2011, respectively.

(15) Postretirement Health Care and Life Insurance Benefits

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

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Net periodic postretirement benefit cost included the following components:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Service cost for benefits earned	$14.9	$13.9	$12.9
Interest cost on accumulated postretirement benefit obligation	54.9	57.9	58.2
Amortization of prior service cost	2.5	2.8	2.6
Amortization of actuarial loss	32.8	26.9	24.9
Net periodic postretirement benefit cost	$105.1	$101.5	$98.6

The following includes pre-tax amounts recorded in "Accumulated other comprehensive income (loss)":

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Net actuarial (gain) loss arising during year	$(68.3)	$86.0	$45.3
Prior service (credit) cost arising during year	(31.9)	(1.4)	7.9
Amortization:			
Actuarial loss	(32.8)	(26.9)	(24.9)
Prior service cost	(2.5)	(2.8)	(2.6)
Total recorded in other comprehensive (income) loss	(135.5)	54.9	25.7
Net periodic postretirement benefit cost	105.1	101.5	98.6
Net periodic postretirement benefit cost, net of amounts recorded in other comprehensive (income) loss	$(30.4)	$156.4	$124.3

The Company amortizes actuarial gain and loss using a 0% corridor with an amortization period that covers the average future working lifetime of active employees (11.75 years and 11.70 years at January 1, 2013 and 2012, respectively). The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic postretirement benefit cost during the year ending December 31, 2013 are $24.1 million and $1.7 million, respectively.

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

	December 31, 2012	2011
	(Dollars in millions)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of period	$1,121.5	$1,031.2
Service cost	14.9	13.9
Interest cost	54.9	57.9
Participant contributions	2.3	1.9
Plan changes[1]	(31.9)	(1.4)
Benefits paid	(67.3)	(68.0)
Actuarial (gain) loss	(68.3)	86.0
Accumulated postretirement benefit obligation at end of period	1,026.1	1,121.5
Change in plan assets:		
Fair value of plan assets at beginning of period	—	—
Employer contributions	65.0	66.1
Participant contributions	2.3	1.9
Benefits paid and administrative fees (net of Medicare Part D reimbursements)	(67.3)	(68.0)
Fair value of plan assets at end of period	—	—
Funded status at end of year	(1,026.1)	(1,121.5)
Less current portion (included in "Accounts payable and accrued expenses")	65.4	68.4
Noncurrent obligation (included in "Accrued postretirement benefit costs")	$(960.7)	$(1,053.1)

(1) Effective January 1, 2013, certain participants for whom the Company pays retiree healthcare liabilities began participation in a Medicare Advantage Program.

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

	December 31, 2012	2011
Discount rate	4.21%	5.05%
Rate of compensation increase	N/A	N/A
Measurement date	December 31, 2012	December 31, 2011

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

	Year Ended December 31, 2012	2011	2010
Discount rate	5.05%	5.81%	6.14%
Rate of compensation increase	N/A	3.50%	3.50%
Measurement date	December 31, 2011	December 31, 2010	December 31, 2009

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

	Year Ended December 31, 2012	2011
Health care cost trend rate assumed for next year	6.43%	9.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.67%	5.00%

Year that the rate reaches the ultimate trend rate	2023	2018

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

	One Percentage-Point Increase	One Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components [1]	$18.1	$(15.6)
Effect on total postretirement benefit obligation [1]	$107.5	$(93.0)

(1) In addition to the effect on total service and interest cost components of expense, changes in trend rates would also increase or decrease the actuarial gain or loss amortization expense component. The impact on actuarial gain or loss amortization would approximate the increase or decrease in the obligation divided by 11.75 years at January 1, 2013.

Plan Assets

The Company's postretirement benefit plans are unfunded.

Estimated Future Benefit Payments

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

	Postretirement Benefits (Dollars in millions)
2013	$65.4
2014	66.5
2015	67.6
2016	68.8
2017	69.5
Years 2018-2022	355.7

(16) Pension and Savings Plans

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

Effective May 31, 2008, the Peabody Plan was frozen in its entirety for both participation and benefit accrual purposes. The Company adopted an enhanced savings plan contribution structure in lieu of benefits formerly accrued under the Peabody Plan.

Net periodic pension cost included the following components:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Service cost for benefits earned	$2.0	$1.7	$1.5
Interest cost on projected benefit obligation	46.7	49.8	50.5
Expected return on plan assets	(63.7)	(64.4)	(58.3)
Amortization of prior service cost	1.0	1.0	1.4

Amortization of actuarial losses	48.6	30.1	21.9
Total net periodic pension cost	$34.6	$18.2	$17.0

The following includes pre-tax amounts recorded in "Accumulated other comprehensive income (loss)":

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Net actuarial loss arising during year	$67.6	$144.2	$13.1
Amortization:			
Actuarial loss	(48.6)	(30.1)	(21.9)
Prior service cost	(1.0)	(1.0)	(1.4)
Total recorded in other comprehensive loss (income)	18.0	113.1	(10.2)
Net periodic pension cost	34.6	18.2	17.0
Net periodic pension cost, net of amounts recorded in other comprehensive loss (income)	$52.6	$131.3	$6.8

The Company amortizes actuarial gain and loss using a 5% corridor with a five-year amortization period. The estimated net actuarial loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic pension cost during the year ending December 31, 2013 are $65.7 million and $1.0 million, respectively.

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

	December 31,	
	2012	2011
	(Dollars in millions)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$963.6	$881.0
Service cost	2.0	1.7
Interest cost	46.7	49.8
Benefits paid	(54.1)	(52.8)
Actuarial loss	100.4	83.9
Projected benefit obligation at end of period	1,058.6	963.6
Change in plan assets:		
Fair value of plan assets at beginning of period	769.6	771.6
Actual return on plan assets	96.5	4.1
Employer contributions	1.7	46.7
Benefits paid	(54.1)	(52.8)
Fair value of plan assets at end of period	813.7	769.6
Funded status at end of year	$(244.9)	$(194.0)
Amounts recognized in the consolidated balance sheets:		
Current obligation (included in "Accounts payable and accrued expenses")	$(1.7)	$(1.7)
Noncurrent obligation (included in "Other noncurrent liabilities")	(243.2)	(192.3)
Net amount recognized	$(244.9)	$(194.0)

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

	December 31,	
	2012	2011
Discount rate	4.10%	5.00%
Measurement date	December 31, 2012	December 31, 2011

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

	Year Ended December 31,		
	2012	2011	2010
Discount rate	5.00%	5.84%	6.19%
Expected long-term return on plan assets	8.00%	8.25%	8.25%
Measurement date	December 31, 2011	December 31, 2010	December 31, 2009

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class (net of inflation) based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results. Effective January 1, 2013, the Company lowered its expected rate of return on plan assets from 8.00% to 7.75% reflecting the impact of the current global economic outlook on expected long-term returns and the Company's asset allocation.

The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for all plans as of December 31, 2012 and 2011. The accumulated benefit obligation for all pension plans was $1,058.6 million and $963.6 million as of December 31, 2012 and 2011, respectively.

Assets of the Plans

Assets of the PIC Master Trust (the Master Trust) are invested in accordance with investment guidelines established by the Peabody Plan Retirement Committee and the Western Plan Retirement Committee (collectively, the Retirement Committees) after consultation with outside investment advisors and actuaries.

The asset allocation targets have been set with the expectation that the assets of the Master Trust will be managed with an appropriate level of risk to fund each Plan’s expected liabilities. To determine the appropriate target asset allocations, the Retirement Committees consider the demographics of each Plan’s participants, the funding status of each Plan, the business and financial profile of the Company and other associated risk preferences. These allocation targets are reviewed by the Retirement Committees on a regular basis and revised as necessary. The current target allocations for assets of the Master Trust are 55% equity securities and 45% fixed income investments. Master Trust assets include real estate investments representing approximately 3% of total Master Trust assets. The Company is in the process of liquidating these real estate holdings.

Assets of the Master Trust are either under active management by third-party investment advisors or in index funds, all selected and monitored by the Retirement Committees. The Retirement Committees have established specific investment guidelines for each major asset class including performance benchmarks, allowable and prohibited investment types and concentration limits. In general, investment guidelines do not permit leveraging the assets held in the Master Trust. The investment managers in the Master Trust, however, may employ various strategies and derivative instruments in establishing overall portfolio characteristics consistent with the guidelines and investment objectives for their portfolios. Equity investment guidelines do not permit entering into put or call options (except as deemed appropriate to manage currency risk), and futures contracts are permitted only to the extent necessary to facilitate liquidity management.

A financial instrument’s level within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation techniques and inputs used for investments measured at fair value, including the general classification of such investments pursuant to the valuation hierarchy.

U.S. equity securities. The Plans invest in U.S. equity securities for growth and diversification. Investment vehicles include a mutual fund that invests in large-cap publicly traded common stocks and a common/collective trust that invests in small-cap publicly traded common stocks. The mutual fund, which is traded on a national securities exchange in an active market, is valued using daily publicly quoted net asset value (NAV) prices and accordingly classified within Level 1 of the valuation hierarchy. The common/collective trust investment, which is not publicly traded on a national securities exchange, is valued using a NAV that is based on a derived price in an active market and accordingly classified within Level 2 of the valuation hierarchy. U.S. equity securities are not subject to liquidity redemption restrictions.

International equity securities. The Plans invest in international equity securities for growth and diversification. Investment vehicles include a common/collective trust that primarily invests in equity securities of companies located in countries other than the U.S. and an exchange traded mutual fund that invests in equity securities of companies in global emerging markets. The common/collective trust is valued on the basis of quotations from the primary market in which they are traded and translated at each valuation date from local currency into U.S. dollars using the mean between the bid and asked market rates for such currencies. The NAV of the common/collective trust, as well as the calculation of the NAV of each underlying investment, are determined in U.S. dollars. The common/collective trust is classified within the Level 2 valuation hierarchy since the NAV is based on a derived price in an active market and is not traded on a national securities exchange. Redemptions for the common/collective trust can only occur on the first business day of each month subject to a notification period and minimum withdrawal limits. The exchange-traded mutual fund is traded on a national securities exchange and valued at quoted market prices in active markets and is classified within Level 1 of the valuation hierarchy. The exchange-traded mutual fund has no liquidity redemption restrictions.

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

Short-term investments. The Plans invest in short-term investments to manage liquidity and for transaction settlement purposes. Investment vehicles primarily include a non-interest bearing cash fund with an earnings credit allowance feature and an institutional mutual fund consisting of diversified portfolios of liquid, short-term instruments of varying maturities. The non-interest bearing cash fund is classified within the Level 1 valuation hierarchy. The institutional mutual fund is classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the fund is not traded on a national securities exchange. Short-term investments are not subject to liquidity redemption restrictions.

Interests in real estate. The Plans invest in real estate interests for diversification. Investments in real estate represent interests in several limited partnerships, which invest in various real estate properties. They are valued using various methodologies, including independent third party appraisals. For some investments, little market activity may exist and determination of fair value is then based on the best information available in the circumstances. This involves a significant degree of judgment by taking into consideration a combination of internal and external factors. Accordingly, interests in real estate are classified within the Level 3 valuation hierarchy. Some limited partnerships issue dividends to their investors in the form of cash distributions that the Plans invest elsewhere within the Master Trust. Certain interests in real estate are subject to liquidity redemption restrictions and voluntary redemptions are generally not permitted. Upon liquidation of the limited partnerships, redemptions will generally be in the form of cash distributions and invested elsewhere within the Master Trust.

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

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

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
U.S. equity securities	$255.6	$83.6	$—	$339.2
International equity securities	43.0	83.1	—	126.1
Mortgage-backed debt securities	—	115.5	—	115.5
U.S. debt securities	5.7	94.6	—	100.3
International debt securities	—	35.4	—	35.4
Corporate debt securities	—	54.9	—	54.9
Short-term investments	8.1	6.4	—	14.5
Interests in real estate	—	—	27.8	27.8
Total assets at fair value	$312.4	$473.5	$27.8	$813.7

	December 31, 2011			
	Level 1 (1)	Level 2 (1)	Level 3	Total
	(Dollars in millions)			
U.S. equity securities	$260.9	$79.5	$—	$340.4
International equity securities	36.4	71.4	—	107.8
Mortgage-backed debt securities	—	98.9	—	98.9
U.S. debt securities	17.0	83.3	—	100.3
International debt securities	—	32.0	—	32.0
Corporate debt securities	—	45.8	—	45.8
Short-term investments	13.5	5.6	—	19.1
Interests in real estate	—	—	25.3	25.3
Total assets at fair value	$327.8	$416.5	$25.3	$769.6

(1) Certain amounts have been revised from a Level 2 to a Level 1 fair value hierarchy classification to conform to the current year presentation, which had no effect on previously reported consolidated results and was not material to the footnotes to the consolidated financial statements.

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

	Year Ended December 31,	
	2012	2011
	(Dollars in millions)	
Balance, beginning of year	$25.3	$47.7
Realized losses	—	(8.9)
Unrealized gains relating to investments still held at the reporting date	2.5	11.4
Purchases, sales and settlements, net	—	(24.9)
Balance, end of year	$27.8	$25.3

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Contributions

Annual contributions to the qualified plans are made in accordance with minimum funding standards and the Company's agreement with the Pension Benefit Guaranty Corporation (PBGC). Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). On July 6, 2012, the Moving Ahead for Progress in the 21st Century Act (MAP-21), a highway reauthorization and student loan bill that included both pension funding stabilization provisions and PBGC premium increases, was signed into law. The pension funding stabilization provisions temporarily increased the discount rates used to determine pension liabilities for purposes of minimum funding requirements. MAP-21 is not expected to change the Company's total required cash contributions over the long term, but is expected to reduce the Company's required cash contributions through 2015 relative to prior law if current interest rate levels persist and the qualified plans' asset returns are in line with expectations. As of December 31, 2012, the Company's qualified plans are expected to be at or above the Pension Protection Act thresholds and will therefore avoid benefit restrictions and at-risk penalties for 2013. The Company expects to contribute approximately $5 million to its pension plans to meet minimum funding requirements for its qualified plans and benefit payments for its non-qualified plans in 2013.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the Master Trust:

	Pension Benefits (Dollars in millions)
2013	$56.6
2014	58.5
2015	60.2
2016	61.8
2017	63.3
Years 2018-2022	328.0

Defined Contribution Plans

The Company sponsors employee retirement accounts under three 401(k) plans for eligible U.S. employees. The Company matches voluntary contributions to each plan up to specified levels. The expense for these plans was $51.1 million, $54.5 million and $51.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. A performance contribution feature in one of the plans allows for additional contributions from the Company based upon meeting specified Company performance targets. Performance contributions paid during the years ended December 31, 2012, 2011 and 2010 were $22.5 million, $20.0 million and $19.8 million, respectively.

(17) Stockholders’ Equity

Common Stock

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

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The following table summarizes common stock activity from January 1, 2010 to December 31, 2012:

	2012	2011	2010
Shares outstanding at the beginning of the year	271.1	270.2	268.2
Stock options exercised	0.2	0.3	1.5
Stock grants to employees	1.5	0.7	0.6
Employee stock purchases	0.3	0.2	0.2
Shares relinquished	(0.3)	(0.3)	(0.3)
Shares repurchased	(4.2)	—	—
Shares outstanding at the end of the year	268.6	271.1	270.2

Preferred Stock and Series Common Stock

The Board of Directors is authorized to issue up to 10.0 million shares of preferred stock and up to 40.0 million shares of series common stock, both with a $0.01 per share par value. The Board of Directors can determine the terms and rights of each series, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company and whether the shares of the series will be convertible into shares of any other class or series, or any other security, of the Company or any other corporation. The Board of Directors may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of preferred stock or series common stock as of December 31, 2012.

Perpetual Preferred Stock

As discussed in Note 12. "Debt," the Company had $732.5 million aggregate principal amount of Convertible Junior Subordinated Debentures outstanding as of December 31, 2012. Perpetual preferred stock issued upon a conversion of the Debentures will be fully paid and non-assessable, and holders will have no preemptive or preferential right to purchase any of the Company's other securities. The perpetual preferred stock has a liquidation preference of $1,000 per share, is not convertible and is redeemable at the Company's option at any time at a cash redemption price per share equal to the liquidation preference plus any accumulated dividends. Holders are entitled to receive cumulative dividends at an annual rate of 3.0875% if and when declared by the Company's Board of Directors. If the Company fails to pay dividends on the perpetual preferred stock for five years, or upon the occurrence of a mandatory trigger event, as defined in the certificate of designations governing the perpetual preferred stock, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay accumulated dividends after the payment in full of any deferred interest on the Debentures, subject to certain limitations. In the event of a mandatory trigger event, the Company may not declare dividends on the perpetual preferred stock other than those funded through the sale of warrants or preferred stock as described above. Any deferred interest on the Debentures at the time of notice of conversion will be reflected as accumulated dividends on the perpetual preferred stock at issuance. Additionally, holders of the perpetual preferred stock are entitled to elect two additional members to serve on the Company's Board of Directors if (i) prior to any remarketing of the perpetual preferred stock, the Company fails to declare and pay dividends with respect to the perpetual preferred stock for 10 consecutive years or (ii) after any successful remarketing or any final failed remarketing of the perpetual preferred stock, the Company fails to declare and pay six dividends thereon, whether or not consecutive. The perpetual preferred stock may be remarketed at the holder's election after December 15, 2046 or earlier, upon the first occurrence of a change of control if the Company does not redeem the perpetual preferred stock. There were no outstanding shares of perpetual preferred stock as of December 31, 2012.

Treasury Stock

Share repurchases. The Company has a share repurchase program for its common stock with an authorized amount of $1.0 billion in which repurchases may be made from time to time based on an evaluation of the Company's outlook and general business conditions, as well as alternative investment and debt repayment options. The share repurchase program does not have an expiration date and may be discontinued at any time. Through December 31, 2012, the Company made total repurchases of 7.7 million shares at a cost of $299.6 million ($199.8 million in 2008 and $99.8 million in 2006), leaving $700.4 million available under the share repurchase program. No share repurchases were made under the share repurchase program during the years ended December 31, 2012, 2011 and 2010.

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The Company’s Chairman and Chief Executive Officer also has authority to direct the Company to repurchase up to $100.0 million of common stock outside the share repurchase program. During the second quarter 2012, the Company utilized existing cash on hand to repurchase 4.2 million shares of outstanding common stock for $99.9 million pursuant to that authority through open-market transactions.

Shares relinquished. The Company allows employees to relinquish common stock to pay estimated taxes upon the payout of performance units that are settled in common stock and the vesting of restricted stock. The number of shares of common stock relinquished was 0.3 million for each of the years ended December 31, 2012, 2011 and 2010. The value of the common stock tendered by employees was based upon the closing price on the dates of the respective transactions.

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

Prior to August 2012, each outstanding share of common stock, par value $0.01 per share, of the Company carried one preferred share purchase right (a Right) that was exercisable if a person or group acquired 15% or more of the Company's common stock. Each Right entitled the holder to purchase one quarter of one-hundredth of a share of Series A Junior Participating Preferred Stock from the Company at an exercise price of $27.50, which in turn provided rights to receive the number of common stock shares having a market value of two times the exercise price of the Right. The Rights were governed by a plan that expired in August 2012. There were no shares of Series A Junior Participating Preferred Stock authorized, issued or outstanding as of December 31, 2012.

(18) Share-Based Compensation

The Company has an equity incentive plan for employees and non-employee directors that allows for the issuance of share-based compensation in the form of stock appreciation rights, restricted stock, performance awards, incentive stock options, nonqualified stock options and deferred stock units. The plan made 14.0 million shares of the Company’s common stock available for grant, with 11.8 million shares available for grant as of December 31, 2012. The Company has two employee stock purchase plans that provide for the purchase of up to 6.0 million shares of the Company’s common stock, with 5.0 million shares authorized for purchase by U.S. employees and 1.0 million shares authorized for purchase by Australian employees.

Share-Based Compensation Expense and Cash Flows

The Company’s share-based compensation expense is recorded in “Selling and administrative expenses” in the consolidated statements of operations. Cash received by the Company upon the exercise of stock options and when employees purchase stock under the employee stock purchase plans is reflected as a financing activity in the consolidated statements of cash flows. Share-based compensation expense and cash flow amounts were as follows:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Share-based compensation expense	$45.4	$43.9	$41.1
Tax benefit	16.7	16.3	15.4
Share-based compensation expense, net of tax benefit	28.7	27.6	25.7
Cash received upon the exercise of stock options and from employee stock purchases	9.4	11.1	22.2
Excess tax benefits related to share-based compensation	8.3	8.1	51.0

As of December 31, 2012, the total unrecognized compensation cost related to nonvested awards was $29.6 million, net of taxes, which is expected to be recognized over 3.75 years with a weighted-average period of 0.8 years.

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Deferred Stock Units

In 2012, 2011 and 2010, the Company granted deferred stock units to each of its non-employee directors. The fair value of these units is equal to the market price of the Company’s common stock at the date of grant. These deferred stock units generally vest after one year and are settled in common stock on the specified distribution date elected by each non-employee director. Beginning in 2011, non-employee directors were also given the option to receive their total annual cash retainer in the form of additional deferred stock units (based on the fair market value of the Company's common stock on the date of grant). The additional grant of deferred stock units is subject to the same grant timing, vesting and distribution date elections as the annual equity compensation grant.

Restricted Stock Awards

The primary share-based compensation tool used by the Company for its employees is awards of restricted stock. The majority of restricted stock awards are granted in January of each year, with a lesser portion granted in the first month of the subsequent three quarters. Awards generally cliff vest after three years of service and only contain a service condition, with compensation cost recognized on a straight-line basis over the requisite service period, net of estimated forfeitures. For awards with service and performance conditions, the Company recognizes compensation cost using the graded-vesting method, net of estimated forfeitures. The fair value of restricted stock is equal to the market price of the Company’s common stock at the date of grant.

A summary of restricted stock award activity is as follows:

	Year Ended December 31, 2012	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2011	1,531,092	$45.16
Granted	1,334,532	34.05
Vested	(594,128)	28.73
Forfeited	(232,165)	45.29
Nonvested at December 31, 2012	2,039,331	$42.34

The total fair value of restricted stock awards granted during the years ended December 31, 2012, 2011 and 2010, was $44.4 million, $36.9 million and $23.3 million, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2012, 2011 and 2010, was $19.9 million, $50.0 million and $20.5 million, respectively.

Stock Options

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

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

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

	Year Ended December 31, 2012	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value (in millions)
Options Outstanding at December 31, 2011	1,884,780	$37.92	5.6	$11.0
Granted	369,782	36.27		
Exercised	(218,281)	9.90		
Forfeited	(211,056)	47.37		
Options Outstanding at December 31, 2012	1,825,225	$39.85	5.7	$2.5
Vested and Exercisable	1,325,951	$37.90	4.6	$2.5

During the years ended December 31, 2012, 2011 and 2010, the total intrinsic value of options exercised, defined as the excess fair value of the underlying stock over the exercise price of the options, was $4.2 million, $10.3 million and $53.7 million, respectively. The weighted-average fair values of the Company’s stock options and the assumptions used in applying the Black-Scholes option pricing model were as follows:

	Year Ended December 31,		
	2012	2011	2010
Weighted-average fair value	$18.59	$33.92	$25.70
Risk-free interest rate	0.9%	2.0%	2.8%
Expected option life	5.0 years	5.0 years	5.0 years
Expected volatility	64.0%	64.1%	64.2%
Dividend yield	0.6%	0.6%	0.6%

Performance Units

Performance units are typically granted annually in January and vest over a three-year measurement period and are primarily limited to senior management personnel. The performance units are usually subject to the achievement of two goals, 50% based on three-year stock price performance compared to both an industry peer group and a S&P index (market condition) and 50% based on a three-year return on capital target (performance condition). The performance units granted in 2012 and 2011 are subject to the achievement of the performance and market conditions, while the 2010 units granted are only subject to the achievement of the market condition. Three performance unit grants are outstanding for any given year. The payouts related to all active grants will be settled in the Company’s common stock.

A summary of performance unit activity is as follows:

	Year Ended December 31, 2012	Weighted Average Remaining Contractual Life
Nonvested at December 31, 2011	260,989	1.5
Granted	218,368	
Forfeited	(75,343)	
Vested	(117,382)	
Nonvested at December 31, 2012	286,632	1.5

As of December 31, 2012, there were 117,382 performance units vested that had an aggregate intrinsic value of $1.1 million and a conversion price per share of $26.63.

The performance condition awards were valued utilizing the grant date fair values of the Company's stock adjusted for dividends foregone during the vesting period. The market condition awards were valued utilizing a Monte Carlo simulation which incorporates the total stockholder return hurdles set for each grant. The assumptions used in the valuations for grants were as follows:

	Year Ended December 31,		
	2012	2011	2010
Risk-free interest rate	0.4 %	1.0 %	1.7 %
Expected volatility	52.8 %	63.9 %	64.1 %
Dividend yield	0.6 %	0.6 %	0.6 %

Employee Stock Purchase Plans

The Company's eligible full-time and part-time employees are able to contribute up to 15% of their base compensation into the employee stock purchase plans, subject to a limit of $25,000 per person per year. Employees are able to purchase Company common stock at a 15% discount to the lower of the fair market value of the Company's common stock on the initial or final trading dates of each six-month offering period. Offering periods begin on January 1 and July 1 of each year. The Company uses the Black-Scholes option pricing model to determine the fair value of employee stock purchase plan share-based payments. The fair value of the six-month "look-back" option in the Company's employee stock purchase plans is estimated by adding the fair value of 0.15 of one share of stock to the fair value of 0.85 of an option on one share of stock. The Company utilized U.S. Treasury yields as of the grant date for its risk-free interest rate assumption, matching the Treasury yield terms to the six-month offering period. The Company utilized historical company data to develop its dividend yield and expected volatility assumptions.

Shares purchased under the plans were 0.3 million for the year ended December 31, 2012, 0.2 million for the year ended December 31, 2011 and 0.2 million for the year ended December 31, 2010.

(19) Accumulated Other Comprehensive Income (Loss)

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

	Foreign Currency Translation Adjustment	Net Actuarial Loss Associated with Postretirement Plans and Workers' Compensation Obligations	Prior Service Cost Associated with Postretirement Plans	Cash Flow Hedges	Available-For-Sale Securities	Total Accumulated Other Comprehensive Income (Loss)
	(Dollars in millions)					
December 31, 2009	$3.1	$ (343.5)	$ (10.4)	$167.3	$ —	$ (183.5)
Net change in fair value	—	—	—	229.9	—	229.9
Reclassification from other comprehensive income to earnings	—	31.8	2.5	(102.4)	—	(68.1)
Current period change	—	(41.3)	(4.9)	—	—	(46.2)
December 31, 2010	3.1	(353.0)	(12.8)	294.8	—	(67.9)
Net change in fair value	—	—	—	291.9	(5.8)	286.1
	—	38.2	2.3	(251.0)	(0.9)	(211.4)

Reclassification from other comprehensive income to earnings						
Current period change	—	(150.1)	0.9	—	—	(149.2)
December 31, 2011	3.1	(464.9)	(9.6)	335.7	(6.7)	(142.4)
Net change in fair value	—	—	—	350.4	(15.5)	334.9
Reclassification from other comprehensive income to earnings	—	53.2	2.2	(298.6)	22.5	(220.7)
Current period change	19.1	—	20.1	—	—	39.2
December 31, 2012	$22.2	$ (411.7)	$ 12.7	$387.5	$ 0.3	$ 11.0

Comprehensive income (loss) differs from net income by the amount of unrealized gain or loss resulting from valuation changes of the Company’s cash flow hedges (see Note 7. "Derivatives and Fair Value Measurements" and Note 8. "Coal Trading" for information related to the Company’s cash flow hedges), changes in the fair value of available-for-sale securities (see Note 6. "Investments" for information related to the Company's investments in available-for-sale securities), the change in actuarial loss and prior service cost of postretirement plans and workers' compensation obligations (see Note 15. "Postretirement Health Care and Life Insurance Benefits" and Note 16. "Pension and Savings Plans" for information related to the Company's postretirement and pension plans) and foreign currency translation adjustment related to the Company's 50% interest in the Middlemount Mine, whose functional currency is the Australian dollar. The values of the Company’s cash flow hedging instruments are primarily affected by changes in diesel fuel, coal prices and the U.S. dollar/Australian dollar exchange rate.

(20) Resource Management and Other Commercial Events

Prairie State Energy Campus (Prairie State)

A subsidiary of the Company owns a 5.06% undivided interest in Prairie State, a 1,600 megawatt coal-fueled electricity generation plant and adjacent coal mine in Washington, St. Clair and Randolph counties in Illinois. On June 6, 2012, the first of two 800 megawatt electricity generation units (Unit 1) commenced commercial operations, with the second 800 megawatt electricity generation unit (Unit 2) initiating commercial operations on November 2, 2012. As a result, the Company reclassified an aggregate total of $246.0 million from "Investments and other assets" in accordance with its undivided interest in the operating assets and liabilities of Prairie State in the consolidated balance sheet during the year ended December 31, 2012 as follows (in millions):

Inventories	$3.6	
Property, plant, equipment and mine development	243.8	
Accounts payable and accrued expenses	(1.4	)
Total, net	$246.0	

Subsequent to June 6, 2012 and November 2, 2012, the 5.06% share of the results of operations of Unit 1 and Unit 2, respectively, have been included in the Company's consolidated statements of operations, which amounted to total revenues of $4.0 million and a loss before income taxes of $6.3 million through December 31, 2012.

In 2011, the Company recognized income associated with the receipt of a $14.6 million project development fee related to its involvement in Prairie State, which was classified in "Other revenues" in the consolidated statement of operations.

Coal Reserves

In 2011, the Company exchanged coal reserves in Kentucky and coal reserves and surface lands in Illinois for coal reserves in West Virginia in a nonmonetary exchange with a third party. Based on the fair value of the coal reserves received, the Company recognized a $37.7 million gain on the exchange, which was classified in "Net gain on disposal or exchange of assets" in the consolidated statement of operations. Fair value was determined by using a discounted cash flow model that included assumptions surrounding future coal sales prices, operating costs and the discount rate. Based on the non-cash nature of the transaction, there was no impact to the investing section of the Company's consolidated statement of cash flows. In 2010, the Company recognized gains of $23.7 million on similar transactions.

In 2011, the Company sold non-strategic coal reserves and surface lands located in Kentucky and Illinois for $24.9 million of cash proceeds and notes receivable totaling $17.4 million and recognized a gain of $31.7 million, which was classified in "Net gain on disposal or exchange of assets" in the consolidated statement of operations. The non-cash portion of these transactions was excluded from the investing section of the consolidated statement of cash flows.

(21) (Loss) Earnings per Share (EPS)

Basic and diluted EPS are computed using the two-class method, which is an earnings allocation that determines EPS for each class of common stock and participating securities according to dividends declared and participation rights in undistributed earnings. The Company's restricted stock awards are considered participating securities because holders are entitled to receive non-forfeitable dividends during the vesting term. Diluted EPS includes securities that could potentially dilute basic EPS during a reporting period, for which the Company includes the Debentures and share-based compensation awards. Dilutive securities are not included in the computation of loss per share when a company reports a net loss as the impact would be anti-dilutive.

A conversion of the Debentures may result in payment for any conversion value in excess of the principal amount of the Debentures in the Company’s common stock. For diluted EPS purposes, potential common stock is calculated based on whether the market price of the Company’s common stock at the end of each reporting period is in excess of the conversion price of the Debentures. For a full discussion of the conditions under which the Debentures may be converted, the conversion rate to common stock and the conversion price, see Note 12. "Debt."

For all but the performance units, the potentially dilutive impact of the Company’s share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation. For the Company’s other share-based compensation awards, performance units, their contingent features result in an assessment for any potentially dilutive common stock by using the end of the reporting period as if it were the end of the contingency period for all units granted. For a full discussion of the Company’s share-based compensation awards, see Note 18.

The computation of diluted EPS excludes anti-dilutive shares of 1.2 million for the year ended December 31, 2012 and approximately 0.1 million for the years ended December 31, 2011 and 2010. These anti-dilutive shares were due to certain share-based compensation awards calculated under the treasury stock method. This anti-dilution generally occurs where the exercise prices are higher than the average market value of the Company’s stock price during the applicable period.

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The following illustrates the earnings allocation method utilized in the calculation of basic and diluted EPS.

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
EPS numerator:			
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$825.0
Less: Net income (loss) attributable to noncontrolling interests	10.6	(11.4)	28.2
(Loss) income from continuing operations attributable to common stockholders before allocation of earnings to participating securities	(481.5)	1,024.2	796.8
Less: Earnings allocated to participating securities	—	5.3	5.6
(Loss) income from continuing operations attributable to common stockholders, after earnings allocated to participating securities[(1)]	(481.5)	1,018.9	791.2
Loss from discontinued operations, net of income taxes	(104.2)	(66.5)	(22.8)
Less: Loss from discontinued operations allocated to participating securities	—	(0.4)	(0.2)
Loss from discontinued operations attributable to common stockholders, after allocation of earnings to participating securities[(1)]	$(104.2)	$(66.1)	$(22.6)
Net (loss) income attributable to common stockholders, after earnings allocated to participating securities[(1)]	$(585.7)	$952.8	$768.6
EPS denominator:			
Weighted average shares outstanding — basic	268.0	269.1	267.0
Impact of dilutive securities	—	1.2	2.9
Weighted average shares outstanding — diluted	268.0	270.3	269.9
Basic EPS attributable to common stockholders:			
(Loss) income from continuing operations	$(1.80)	$3.78	$2.96
Loss from discontinued operations	(0.39)	(0.25)	(0.08)
Net (loss) income attributable to common stockholders	$(2.19)	$3.53	$2.88
Diluted EPS attributable to common stockholders:			
(Loss) income from continuing operations	$(1.80)	$3.77	$2.92
Loss from discontinued operations	(0.39)	(0.25)	(0.08)
Net (loss) income attributable to common stockholders	$(2.19)	$3.52	$2.84

(1) The reallocation adjustment for participating securities to arrive at the numerator used to calculate diluted EPS was less than $0.1 million for 2011 and 2010.

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(22) Management — Labor Relations

On December 31, 2012, the Company had approximately 8,200 employees worldwide, excluding those employees that were employed at operations classified as discontinued operations and including approximately 5,700 hourly employees. Approximately 30% of those hourly employees were represented by organized labor unions and were employed by mines that generated 19% of the Company's 2012 coal production. In the U.S., two of the Company's mines were represented by organized labor unions, one of which commenced closure activity during the fourth quarter of 2012. In Australia, the coal mining industry is unionized and the majority of workers employed at the Company's Australian Mining operations are members of trade unions. The Construction Forestry Mining and Energy Union represents the Company's Australian subsidiaries' hourly production and engineering employees, including those employed through contract mining relationships. The Company believes labor relations with its employees are good. Should that condition change, the Company could experience labor disputes, work stoppages or other disruptions in production that could negatively impact the Company's results of operations and cash flows. The following table presents the Company's operations in which the employees are represented by organized labor unions:

Mine	Current Agreement Expiration Date
U. S.	
Willow Lake [(1)]	-
Willow Lake Preparation Facility [(1)]	December 2014
Kayenta [(2)]	September 2013
Australia	
Owner-operated mines:	
Wilkie Creek [(3)]	May 2013
Metropolitan [(4)]	June 2013
Coppabella [(4)]	August 2013
Wambo Coal Handling Plant	October 2014
North Wambo Underground	April 2015
North Goonyella	July 2015
Contractor-operated mines:	
Eaglefield	July 2014
Wambo Open-Cut	August 2014
Moorvale	March 2015
Millennium	October 2015
Wilpinjong	May 2016
Burton	December 2016

(1) The labor agreement for the hourly workers at the Company's Willow Lake Mine in Illinois expired in April 2011. The mine continued to operate without a labor agreement until closure activities were initiated at that site in November 2012. The preparation facility will continue to service the Company's Cottage Grove and Wildcat Hills Underground Mines. Refer to Note 3. "Asset Impairment and Mine Closure Costs" for additional details regarding the closure.

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

year ended December 31, 2012.

(3) The Wilkie Creek Mine was classified as held for sale within discontinued operations as of December 31, 2012.

(4) Negotiations for the Metropolitan and Coppabella mines are underway.

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

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

Financial Instruments with Off-Balance Sheet Risk

As of December 31, 2012, the Company had the following financial instruments with off-balance-sheet risk:

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Other[1]	Total
	(Dollars in millions)				
Self bonding	$1,275.8	$—	$—	$—	$1,275.8
Surety bonds	316.5	105.3	29.4	8.8	460.0
Bank guarantees	255.1	—	—	175.3	430.4
Letters of credit	—	—	24.1	81.3	105.4
	$1,847.4	$105.3	$53.5	$265.4	$2,271.6

(1) Other includes the $79.7 million in letters of credit described below and an additional $185.7 million in bank guarantees, letters of credit and surety bonds related to collateral for surety companies, road maintenance, performance guarantees and other operations.

The Company owns a 37.5% interest in Dominion Terminal Associates, a partnership that operates a coal export terminal in Newport News, Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The partners have severally (but not jointly) agreed to make payments under various agreements which in the aggregate provide the partnership with sufficient funds to pay rents and to cover the principal and interest payments on the floating-rate industrial revenue bonds issued by the Peninsula Ports Authority, and which are supported by letters of credit from a commercial bank. As of December 31, 2012, the Company's maximum reimbursement obligation to the commercial bank was in turn supported by four letters of credit totaling $42.7 million.

The Company is party to an agreement with the PBGC and TXU Europe Limited, an affiliate of the Company's former parent corporation, under which the Company is required to make special contributions to two of the Company's defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If the Company or the PBGC gives notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if the Company fails to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employee Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guarantee in place from TXU Europe Limited in favor of the PBGC before it draws on the Company's letter of credit. On November 19, 2002, TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the U.S.) and continues under this process as of December 31, 2012. As a result of these proceedings, TXU Europe Limited may be liquidated or otherwise reorganized in such a way as to relieve it of its obligations under its guarantee.

Accounts Receivable Securitization

The Company has an accounts receivable securitization program (securitization program) with a maximum capacity of $275.0 million through its wholly-owned, bankruptcy-remote subsidiary (Seller). At December 31, 2012, the Company had $191.5 million available under the securitization program, net of amounts drawn. Under the securitization program, the Company contributes trade receivables of most of the Company’s U.S. subsidiaries on a revolving basis to the Seller, which then sells the receivables in their entirety to a consortium of unaffiliated asset-backed commercial paper conduits (the Conduits). After the sale, the Company, as servicer of the assets, collects the receivables on behalf of the Conduits for a nominal servicing fee. The Company utilizes proceeds from the sale of its accounts receivable as an alternative to short-term borrowings under the revolving credit facility portion of the Company's Credit Facility, effectively managing its overall borrowing costs and providing an additional source for working capital. The securitization program extends to May 2013, at which time the Company expects to seek renewal of that program. 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, 2012, the Company received total consideration of $4,377.8 million related to accounts receivable sold under the securitization program, including $2,834.5 million of cash up front from the sale of the receivables, an additional $1,247.7 million of cash upon the collection of the underlying receivables and $295.6 million that had not been collected at December 31, 2012 and was recorded at carrying value, which approximates fair value. The reduction in accounts receivable as a result of securitization activity with the Conduits was $25.0 million and $150.0 million at December 31, 2012 and 2011, respectively.

The securitization activity has been reflected in the consolidated statements of cash flows as operating activity because both the cash received from the Conduits upon sale of receivables as well as the cash received from the Conduits upon the ultimate collection of receivables are not subject to significantly different risks given the short-term nature of the Company’s trade receivables. The Company recorded expense associated with securitization transactions of $2.0 million, $2.0 million and $2.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Patriot Bankruptcy

On October 31, 2007, the Company spun off companies that constituted portions of its former Eastern U.S. Mining operations business segment to form Patriot Coal Corporation (Patriot). The spin-off included eight company-operated mines, two majority-owned joint venture mines and numerous contractor-operated mines serviced by eight coal preparation facilities, along with 1.2 billion tons of proven and probable coal reserves. On July 9, 2012, Patriot and certain of its wholly owned subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Southern District of New York. The case was subsequently moved to the U.S. Bankruptcy Court for the Eastern District of Missouri.

The Company believes that its only material exposure to the bankruptcy of Patriot relates to up to $150 million in possible federal and state black lung occupational disease liabilities. As Patriot noted in its Annual Report on Form 10-K/A for the year ended December 31, 2011, it has posted $15 million in collateral with the U.S. Department of Labor (DOL) in exchange for the right to self-insure its liabilities under the Federal Coal Mine Health and Safety Act of 1969 (Black Lung Act). If Patriot is unable to meet its black lung liability obligations, the Company believes that the DOL will first look to this collateral for payment. The Black Lung Act allows the DOL to seek recovery from other potentially liable operators as well. The Company may be considered a potentially liable operator for purposes of the Black Lung Act with respect to the black lung liabilities of Patriot at the time of the spin-off.

The Company also has a small number of commercial arrangements with Patriot and believes its potential exposure under these agreements will not have a material adverse effect on its consolidated results of operations, financial condition or cash flows.

Other

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

The Company has provided financial guarantees under certain long-term debt agreements entered into by its subsidiaries and substantially all of the Company’s U.S. subsidiaries provide financial guarantees under long-term debt agreements entered into by the Company. The maximum amounts payable under the Company’s debt agreements are equal to the respective principal and interest payments.

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(24) Commitments and Contingencies

Commitments

Unconditional Purchase Obligations

As of December 31, 2012, purchase commitments for capital expenditures were $494.6 million, all of which is obligated within the next three years, with $457.9 million obligated in the next year. In Australia, the Company has generally secured the ability to transport coal through rail contracts and ownership interests in three east coast coal export terminals that are primarily funded through take-or-pay arrangements with terms ranging up to 28 years. In the U.S., the Company has entered into certain long-term coal export terminal agreements to secure and expand its Gulf Coast export platform. As of December 31, 2012, these Australian and U.S. commitments under take-or-pay arrangements totaled $4,355.4 million, of which $424.3 million is obligated within the next year.

Federal Coal Leases

In the second quarter of 2012, the Company was named by the U.S. Department of the Interior, Bureau of Land Management (BLM) as the winning bidder for control of approximately 1.1 billion tons of federal coal reserves adjacent to its North Antelope Rochelle Mine in the Southern Powder River Basin of Wyoming, with a weighted average bid price of approximately $1.10 per mineable ton. Consequently, the Company made aggregate payments of $247.9 million during the year ended December 31, 2012 pursuant to the two associated federal coal leases, with remaining annual payments of $247.9 million due in each of the next four years.

In July 2011, the Company was named by the BLM as the winning bidder for control of approximately 220 million tons of federal coal reserves adjacent to its Caballo Mine in the Powder River Basin at a bid price of $0.95 per mineable ton, with payments of $42.1 million due annually in each of the years from 2011 through 2015 pursuant to the associated federal coal lease (the Belle Ayr North Lease). Similarly, in September 2011, a subsidiary of Alpha Natural Resources, Inc. (Alpha) was named by the BLM as the winning bidder for control of approximately 130 million tons of federal coal reserves in the Powder River Basin at a bid price of $1.10 per mineable ton, with contractual payments of $28.6 million due annually in each of the years from 2011 through 2015 under the associated federal coal lease (the Caballo West Lease). In July 2012, the Company and Alpha executed a lease exchange agreement with the BLM whereby the Company agreed to sell, assign and transfer its interest in the Belle Ayr North Lease in exchange for (i) Alpha's interest in the Caballo West Lease, (ii) reimbursement of $13.5 million for the difference in the related federal coal lease payments made by each party in 2011 and (iii) five annual true up payments of $3.9 million for the excess of the $1.10 bid price per mineable ton assumed under the Caballo West Lease over the $0.95 price under the transferred lease. An aggregate of $21.3 million was received from Alpha during the year ended December 31, 2012 for the reimbursement payment and first and second true up payments, which is classified in "Proceeds from disposal of assets, net of notes receivable" in the consolidated statement of cash flows for that period. The three remaining annual true up payments are due from Alpha on November 1 in each of the years from 2013 through 2015.

The federal coal leases executed with the BLM described above expire after a 20-year initial term, unless at such time there is ongoing production on the subject leases or within an active logical mining unit of which they are part.

Contingencies

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

Litigation Relating to Continuing Operations

Gulf Power Company. On June 22, 2006, Gulf Power Company (Gulf Power) filed a breach of contract lawsuit against a Company subsidiary in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration by the Company's subsidiary under a coal supply agreement with Gulf Power and seeking damages for alleged past and future tonnage shortfalls of nearly five million tons under the agreement, which expired on December 31, 2007. On June 30, 2009, the court granted Gulf Power's motion for partial summary judgment on liability and denied the Company subsidiary's motion for summary judgment. On September 30, 2010, the court entered its order on damages, awarding Gulf Power zero dollars in damages and the Company subsidiary its costs to defend the lawsuit. On November 1, 2010, Gulf Power filed a motion to alter or amend the judgment, contesting the trial court's damages order, to which the Company subsidiary objected. The court entered an order on July 29, 2011 that affirmed its September 30, 2010 decision in all respects except for 2007 cover coal purchases and granted in part Gulf Power's motion to alter judgment with respect to 2007 cover coal purchases. On September 30, 2011, the court entered an order awarding Gulf Power damages in the amount of $20.5 million for its 2007 cover coal purchases. On January 19, 2012, the court entered its order awarding Gulf Power prejudgment interest in the amount of $6.9 million plus post-judgment interest. The Company's subsidiary has filed its notice of appeal and briefing is complete. Oral arguments before the U.S. Court of Appeals for the Eleventh Circuit occurred on January 31, 2013. Based on the Company's evaluation of information currently available concerning the issues and their potential impact, the Company believes that its subsidiary will be successful in the liability appeals process and, therefore, no liability has been recorded at this time.

Monto Coal Pty Limited, Monto Coal 2 Pty Ltd Limited and Macarthur Coal Limited. In October 2007, a statement of claim was delivered to Monto Coal Pty Ltd, a wholly owned subsidiary of PEA-PCI, then Macarthur Coal Limited, and Monto Coal 2 Pty Ltd, an equity accounted investee, from the minority interest holders in the Monto Coal Joint Venture, alleging that Monto Coal 2 Pty Ltd breached the Monto Coal Joint Venture Agreement and Monto Coal Pty Ltd breached the Monto Coal Management Agreement. Monto Coal Pty Ltd is the manager of the Monto Coal Joint Venture pursuant to the Management Agreement. Monto Coal 2 Pty Ltd holds a 51% interest in the Monto Coal Joint Venture. The plaintiffs are Sanrus Pty Ltd, Edge Developments Pty Ltd and H&J Enterprises (Qld) Pty Ltd. An additional statement of claim was delivered to PEA-PCI in November 2010 from the same minority interest holders in the Monto Coal Joint Venture, alleging that PEA-PCI induced Monto Coal 2 Pty Ltd and Monto Coal Pty Ltd to breach the Monto Coal Joint Venture Agreement and the Monto Coal Management Agreement, respectively. These actions, which are pending before the Supreme Court of Queensland, Australia, seek damages from the three defendants collectively of no less than $1,193.2 million Australian dollars, plus interest and costs. The defendants dispute the claims and are vigorously defending their positions. Based on the Company's evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes these claims are likely to be finalized without a material adverse effect on its financial condition, results of operations or cash flows.

Claims and Litigation Relating to Indemnities or Historical Operations

Patriot Coal Corporation. On October 23, 2012, eight individual plaintiffs and the UMWA filed a putative class action lawsuit in the U.S. District Court for the Southern District of West Virginia against Peabody Holding Company, LLC, Peabody Energy Corporation and an unrelated coal company. The lawsuit seeks to have the court obligate the defendants to maintain certain Patriot Coal Corporation benefit plans at their current levels and to find the defendants' actions in violation of the Employee Retirement Income Security Act of 1974. On January 7, 2013, the Company defendants filed a motion to dismiss the complaint for failure to state a claim upon which relief can be granted. The plaintiffs thereafter amended their complaint to include new allegations and name two more individuals as plaintiffs. The Company defendants updated their motion to dismiss to respond to the new allegations and filed it on February 20, 2013. The Company believes the lawsuit is without merit and will vigorously defend against it.

Environmental Claims and Litigation

Claims Arising From Historical, Non-Coal Producing Operations. Gold Fields Mining, LLC (Gold Fields) is a dormant, non-coal producing entity that was previously managed and owned by Hanson plc, the Company's predecessor owner. In a February 1997 spin-off, Hanson plc transferred ownership of Gold Fields to the Company, despite the fact that Gold Fields had no ongoing operations and the Company had no prior involvement in its past operations. Gold Fields is currently one of the Company's subsidiaries. The Company indemnified TXU Group with respect to certain claims relating to the historical operations of a former affiliate of Gold Fields.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Environmental claims for remediation, past costs, future costs, and/or natural resource damages have been asserted against Gold Fields related to historical activities of Gold Fields or a former affiliate. Gold Fields or the former affiliate has been named a potentially responsible party (PRP) at five national priority list sites based on the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). CERCLA claims were asserted at 13 additional sites, bringing the total to 18, which have since been reduced to 10 by completion of work, transfer or regulatory inactivity. The number of CERCLA sites in and of itself is not a relevant measure of liability because the nature and extent of environmental concerns and costs varies by site, as does the estimated share of responsibility relative to other PRPs for Gold Fields or the former affiliate.

Undiscounted liabilities for environmental cleanup-related costs for all of the sites noted above were $46.7 million as of December 31, 2012 and $52.5 million as of December 31, 2011, $10.6 million and $11.6 million of which was reflected as a current liability, respectively. These amounts represent those costs that the Company believes are probable and reasonably estimable.

Significant uncertainty exists as to whether claims will be pursued against Gold Fields or the former affiliate in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than the liabilities recorded in the consolidated balance sheets. Based on the Company's evaluation of the issues and their potential impact, the total amount of any future loss cannot be reasonably estimated. However, based on current information, the Company believes these claims are likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

Native Village of Kivalina and City of Kivalina v. ExxonMobil Corporation, et al. In February 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against the Company, several owners of electricity generating facilities and several oil companies. The plaintiffs are the governing bodies of a village in Alaska that they contend is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for nuisance, and allege that the defendants have acted in concert and are jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village. The defendants filed motions to dismiss on the grounds of lack of personal and subject matter jurisdiction. In June 2009, the court granted defendants' motion to dismiss for lack of subject matter jurisdiction finding that plaintiffs' federal claim for nuisance is barred by the political question doctrine and for lack of standing. The plaintiffs appealed the court's dismissal to the U.S. Court of Appeals for the Ninth Circuit, which affirmed the dismissal on September 21, 2012. On October 4, 2012, the plaintiffs filed a Petition for Rehearing En Banc, which was denied.

Other

At times the Company becomes a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where the Company does business. For example, in June 2007, the New York Office of the Attorney General served a letter and subpoena on the Company, seeking information and documents relating to the Company's disclosure to investors of risks associated with possible climate change and related legislation and regulations. The Company believes it has made full and proper disclosure of these potential risks. In addition, in January 2013, the Securities and Exchange Commission (SEC) staff served a subpoena on the Company seeking information and documents relating to the development of Prairie State. The Company is cooperating with the SEC's investigation. Based on current information, the Company believes that such other pending or threatened proceedings are likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(25) Summary of Quarterly Financial Information (Unaudited)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2012 and 2011 is presented below.

	Year Ended December 31, 2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$2,020.7	$1,981.1	$2,058.8	$2,016.9
Operating profit (loss)	351.3	276.7	266.5	(722.0)
Income (loss) from continuing operations, net of income taxes	183.0	214.5	122.9	(991.3)
Net income (loss)	178.3	207.8	41.6	(1,002.8)
Net income (loss) attributable to common stockholders	172.7	204.7	42.9	(1,006.0)
Basic EPS — continuing operations[1]	$0.65	$0.78	$0.46	$(3.73)
Diluted EPS — continuing operations[1]	0.65	0.78	0.46	(3.73)
Weighted average shares used in calculating basic EPS	270.1	269.2	266.2	266.3
Weighted average shares used in calculating diluted EPS	270.9	269.8	266.8	266.3

(1) EPS for the quarters may not sum to the amounts for the year as each period is computed on a discrete basis.

Operating profit (loss) for the third and fourth quarter of 2012 reflected $7.7 million and $921.3 million, respectively, of asset impairment and mine closure costs. Income (loss) from continuing operations, net of income taxes, for all quarters in 2012 included the non-cash impact of the remeasurement of non-U.S. income tax accounts, which amounted to additional tax expense of $8.9 million and $13.6 million in the first and third quarter of 2012, respectively, and a tax benefit of $13.8 million and $0.8 million in the second and fourth quarter of 2012, respectively. Income (loss) from continuing operations, net of income taxes, for the second and fourth quarter of 2012 included net tax benefits related to the acquisition restructuring of PEA-PCI of $59.7 million and $15.0 million, respectively. Income (loss) from continuing operations, net of income taxes, for the third and fourth quarter of 2012 reflected net tax benefits of $2.9 million and $227.3 million, respectively, related to asset impairment and mine closure costs. Income (loss) from continuing operations, net of income taxes, for the fourth quarter of 2012 also included income tax charges related to a net deferred tax liability recognized in connection with the MRRT and an increase in valuation allowance against Australian loss carryforwards of $77.2 million and $332.2 million, respectively. Net income (loss) for the third quarter of 2012 reflected $75.0 million of after-tax asset impairment and mine closure costs related to a discontinued operation.

	Year Ended December 31, 2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$1,723.8	$1,961.7	$1,980.6	$2,229.8
Operating profit	312.6	479.4	385.5	418.2
Income from continuing operations, net of income taxes	193.6	306.5	291.2	221.5
Net income	178.7	292.2	281.4	194.0
Net income attributable to common stockholders	176.5	284.8	274.0	222.4
Basic EPS — continuing operations[1]	$0.71	$1.10	$1.05	$0.92
Diluted EPS — continuing operations[1]	0.70	1.10	1.04	0.92

Weighted average shares used in calculating basic EPS	268.9	269.0	269.2	269.3
Weighted average shares used in calculating diluted EPS	272.8	270.5	270.6	270.2

(1) EPS for the quarters may not sum to the amounts for the year as each period is computed on a discrete basis.

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Operating profit for the third and fourth quarter of 2011 reflected $9.1 million and $76.1 million, respectively, of acquisition costs related to the PEA-PCI acquisition and an adverse impact of a roof fall and recovery of longwall operations at the Company's North Goonyella Mine in Australia of $122.9 million and $111.8 million, respectively. Income from continuing operations, net of income taxes, for all quarters in 2011 included the non-cash impact of the remeasurement of non-U.S. income tax accounts, which amounted to additional tax expense of $6.4 million, $15.4 million and $16.0 million in the first, second and fourth quarter of 2011, respectively, and a tax benefit of $38.7 million in the third quarter of 2011. PEA-PCI results have been included in the Company's results of operations from the date of acquisition on October 26, 2011.

(26) Segment and Geographic Information

The Company reports its operations primarily through the following reportable operating segments: Western U.S. Mining, Midwestern U.S. Mining, Australian Mining, Trading and Brokerage and Corporate and Other.

The Company's Western U.S. Mining operations reflect the aggregation of the Powder River Basin, Southwest and Colorado mining operations. The mines in that segment are characterized by predominantly surface mining extraction processes, coal with a lower sulfur content and Btu and higher customer transportation costs (due to longer shipping distances). The Company's Midwestern U.S. Mining operations reflect the Company’s Illinois and Indiana mining operations, which are characterized by a mix of surface and underground mining extraction processes, coal with a higher sulfur content and Btu and lower customer transportation costs (due to shorter shipping distances). Geologically, Western operations mine bituminous and sub-bituminous coal deposits, and Midwestern operations mine bituminous coal deposits. 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 in the U.S., with a portion sold into the seaborne markets.

The Company’s Australian Mining operations consist of its 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 coal. The business of the Company's Australian Mining operations are primarily export focused with customers spread across several countries, while a portion of the 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.

The Company’s Trading and Brokerage segment brokers coal sales of other coal producers both as principal and agent, and trades coal and freight-related contracts. Corporate and Other includes selling and administrative expenses, equity income (loss) from the Company's joint ventures, certain asset sales, resource management costs and revenues, coal royalty expense, costs associated with past mining obligations, expenses related to the Company’s other commercial activities such as generation development and Btu Conversion costs and provisions for certain litigation.

The Company’s chief operating decision maker uses Adjusted EBITDA as the primary measure of segment profit and loss. The Company defines Adjusted EBITDA as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expense, depreciation, depletion and amortization, asset impairment and mine closure costs and amortization of basis difference associated with equity method investments.

Operating segment results for the year ended December 31, 2012 were as follows (total assets as of December 31, 2012):

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in millions)					
Revenues	$2,949.3	$1,403.7	$3,503.6	$199.9	$21.0	$8,077.5
Adjusted EBITDA	832.8	427.0	938.9	119.7	(481.9)	1,836.5

Total assets	3,248.6	507.7	7,990.8	544.4	3,517.5	15,809.0
Total property, plant, equipment and mine development, net	2,886.8	486.6	6,595.5	2.1	1,830.7	11,801.7
Additions to property, plant, equipment and mine development	121.4	74.7	743.4	0.1	46.4	986.0
Federal coal lease expenditures	276.5	—	—	—	—	276.5
Loss from equity affiliates	—	—	—	—	61.2	61.2

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Operating segment results for the year ended December 31, 2011 were as follows (total assets as of December 31, 2011):

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in millions)					
Revenues	$2,900.4	$1,402.6	$3,080.7	$475.1	$37.1	$7,895.9
Adjusted EBITDA	766.0	402.9	1,194.3	197.0	(437.6)	2,122.6
Total assets	3,095.8	590.6	8,440.4	633.3	3,972.9	16,733.0
Total property, plant, equipment and mine development, net	2,785.1	502.4	6,371.3	1.7	1,591.1	11,251.6
Additions to property, plant, equipment and mine development	186.1	99.9	490.8	0.9	69.7	847.4
Federal coal lease expenditures	42.4	—	—	—	—	42.4
Loss from equity affiliates	—	—	—	—	19.2	19.2

Operating segment results for the year ended December 31, 2010 were as follows (total assets as of December 31, 2010):

	Western U.S. Mining	Midwestern U.S. Mining	Australian Mining	Trading and Brokerage	Corporate and Other	Consolidated
	(Dollars in millions)					
Revenues	$2,706.3	$1,248.9	$2,399.9	$291.1	$22.0	$6,668.2
Adjusted EBITDA	816.7	309.9	977.4	77.2	(354.7)	1,826.5
Total assets	3,008.4	528.5	3,556.9	398.2	3,871.1	11,363.1
Total property, plant, equipment and mine development, net	2,672.8	508.4	2,559.4	1.2	1,521.5	7,263.3
Additions to property, plant, equipment and mine development	143.3	223.0	138.7	0.9	40.1	546.0
Loss from equity affiliates	—	—	—	—	1.7	1.7

A reconciliation of Adjusted EBITDA to consolidated income from continuing operations, net of income taxes follows:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in millions)		
Total Adjusted EBITDA	$1,836.5	$2,122.6	$1,826.5
Depreciation, depletion and amortization	(663.4)	(474.3)	(429.5)
Asset retirement obligation expenses	(67.0)	(52.6)	(45.9)
Asset impairment and mine closure costs	(929.0)	—	—
Amortization of basis difference	(4.6)	—	—
Interest expense	(405.6)	(238.6)	(222.0)
Interest income	24.5	18.9	9.6
Income tax provision	(262.3)	(363.2)	(313.7)
(Loss) income from continuing operations, net of income taxes	$(470.9)	$1,012.8	$825.0

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The following table presents revenues as a percent of total revenue from external customers by geographic region:

	Year Ended December 31,		
	2012	2011	2010
U.S.	55.4 %	61.0 %	63.5 %
Japan	12.3 %	10.2 %	9.1 %
China	6.8 %	2.8 %	2.7 %
South Korea	5.8 %	5.5 %	3.7 %
India	4.1 %	5.2 %	4.9 %
Other	15.6 %	15.3 %	16.1 %
Total	100.0 %	100.0 %	100.0 %

The Company attributes revenue to individual countries based on the location of the physical delivery of the coal.

(27) Supplemental Guarantor/Non-Guarantor Financial Information

In accordance with the indentures governing the Senior Notes, including the 5.875% Senior Notes due April 2016 and the 6.875% Senior Notes due March 2013 extinguished in 2011 and 2010, respectively, certain wholly-owned U.S. subsidiaries of the Company have fully and unconditionally guaranteed these Senior Notes, on a joint and several basis. Separate financial statements and other disclosures concerning the Guarantor Subsidiaries are not presented because management believes that such information is not material to the holders of the Senior Notes. The following historical financial statement information is provided for the Guarantor/Non-Guarantor Subsidiaries.

PEABODY ENERGY CORPORATION

SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Year Ended December 31, 2012				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$—	$ 4,571.3	$ 3,729.2	$ (223.0)	$ 8,077.5
Costs and expenses					
Operating costs and expenses	(395.2)	3,344.1	3,206.8	(223.0)	5,932.7
Depreciation, depletion and amortization	—	315.6	347.8	—	663.4
Asset retirement obligation expenses	—	42.9	24.1	—	67.0
Selling and administrative expenses	38.7	199.7	30.4	—	268.8
Other operating (income) loss:					
Net gain on disposal or exchange of assets	—	(14.7)	(2.4)	—	(17.1)
Asset impairment and mine closure costs	35.5	86.8	806.7	—	929.0
Loss from equity affiliates and investment in subsidiaries	720.0	12.5	48.7	(720.0)	61.2
Interest expense	413.9	13.9	475.6	(497.8)	405.6
Interest income	(309.8)	(149.1)	(63.4)	497.8	(24.5)
Unrealized (gain) loss on derivatives	—	(35.3)	35.3	—	—
(Loss) income from continuing operations before income taxes	(503.1)	754.9	(1,180.4)	720.0	(208.6)
Income tax provision	80.2	105.8	76.3	—	262.3
(Loss) income from continuing operations, net of income taxes	(583.3)	649.1	(1,256.7)	720.0	(470.9)
Loss from discontinued operations, net of income taxes	(2.4)	(82.2)	(19.6)	—	(104.2)
Net (loss) income	(585.7)	566.9	(1,276.3)	720.0	(575.1)
Less: Net income attributable to noncontrolling interests	—	—	10.6	—	10.6
Net (loss) income attributable to common stockholders	$ (585.7)	$ 566.9	$ (1,286.9)	$ 720.0	$ (585.7)

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Year Ended December 31, 2011				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$—	$ 4,679.9	$ 3,509.4	$ (293.4)	$ 7,895.9
Costs and expenses					
Operating costs and expenses	(386.3)	3,526.2	2,631.1	(293.4)	5,477.6
Depreciation, depletion and amortization	—	289.5	184.8	—	474.3
Asset retirement obligation expenses	—	35.7	16.9	—	52.6
Selling and administrative expenses	34.0	215.0	19.2	—	268.2
Acquisition costs related to Macarthur Coal Limited	32.8	31.2	21.2	—	85.2
Other operating (income) loss:					
Net gain on disposal or exchange of assets	—	(73.2)	(3.7)	—	(76.9)
(Income) loss from equity affiliates and investment in subsidiaries	(881.5)	8.6	10.6	881.5	19.2
Interest expense	243.1	47.3	67.2	(119.0)	238.6
Interest income	(50.9)	(31.1)	(55.9)	119.0	(18.9)
Unrealized (gain) loss on derivatives	—	(1.3)	1.3	—	—
Income from continuing operations before income taxes	1,008.8	632.0	616.7	(881.5)	1,376.0
Income tax provision	46.5	172.0	144.7	—	363.2
Income from continuing operations, net of income taxes	962.3	460.0	472.0	(881.5)	1,012.8
Loss from discontinued operations, net of income taxes	(4.6)	(5.4)	(56.5)	—	(66.5)
Net income	957.7	454.6	415.5	(881.5)	946.3
Less: Net loss attributable to noncontrolling interests	—	—	(11.4)	—	(11.4)
Net income attributable to common stockholders	$957.7	$ 454.6	$ 426.9	$ (881.5)	$ 957.7

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Year Ended December 31, 2010				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Total revenues	$—	$ 3,524.4	$ 3,916.9	$ (773.1)	$ 6,668.2
Costs and expenses					
Operating costs and expenses	(145.1)	2,413.1	3,142.8	(773.1)	4,637.7
Depreciation, depletion and amortization	—	286.5	143.0	—	429.5
Asset retirement obligation expenses	—	30.6	15.3	—	45.9
Selling and administrative expenses	31.6	194.3	6.3	—	232.2
Other operating (income) loss:					
Net (gain) loss on disposal or exchange of assets	—	(34.4)	4.5	—	(29.9)
(Income) loss from equity affiliates and investment in subsidiaries	(838.4)	7.1	6.0	827.0	1.7
Interest expense	219.7	52.7	17.9	(68.3)	222.0
Interest income	(18.8)	(21.8)	(37.3)	68.3	(9.6)
Income from continuing operations before income taxes	751.0	596.3	618.4	(827.0)	1,138.7
Income tax (benefit) provision	(24.2)	181.6	156.3	—	313.7
Income from continuing operations, net of income taxes	775.2	414.7	462.1	(827.0)	825.0
Loss from discontinued operations, net of income taxes	(1.2)	(21.6)	—	—	(22.8)
Net income	774.0	393.1	462.1	(827.0)	802.2
Less: Net income attributable to noncontrolling interests	—	—	28.2	—	28.2
Net income attributable to common stockholders	$774.0	$ 393.1	$ 433.9	$ (827.0)	$ 774.0

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31, 2012				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Net (loss) income	$(585.7)	$566.9	$ (1,276.3)	$720.0	$ (575.1)
Other comprehensive income, net of income taxes:					
Net change in unrealized gains (losses) on available-for-sale securities (net of $4.0 tax provision)					
Unrealized holding losses on available-for-sale securities	(15.5)	—	—	—	(15.5)
Less: Reclassification for realized losses included in net income	22.5	—	—	—	22.5
Net change in unrealized gains on available-for-sale securities	7.0	—	—	—	7.0
Net unrealized losses on cash flow hedges (net of $3.9 tax benefit)					
Increase in fair value of cash flow hedges	205.9	—	144.5	—	350.4
Less: Reclassification for realized gains included in net income	(249.1)	—	(49.5)	—	(298.6)
Net unrealized (losses) gains on cash flow hedges	(43.2)	—	95.0	—	51.8
Postretirement plans and workers' compensation obligations (net of $43.9 tax provision)					
Prior service cost for the period	—	20.1	—	—	20.1
Net actuarial (loss) gain for the period	—	(0.9)	0.9	—	—
Amortization of actuarial loss and prior service cost	—	54.5	0.9	—	55.4
Postretirement plan and workers' compensation obligations	—	73.7	1.8	—	75.5
Foreign currency translation adjustment	—	—	19.1	—	19.1
Other comprehensive income from investment in subsidiaries	189.6	—	—	(189.6)	—
Other comprehensive income, net of income taxes	153.4	73.7	115.9	(189.6)	153.4
Comprehensive (loss) income	(432.3)	640.6	(1,160.4)	530.4	(421.7)
Less: Comprehensive income attributable to noncontrolling interests	—	—	10.6	—	10.6
Comprehensive (loss) income attributable to common stockholders	$(432.3)	$640.6	$ (1,171.0)	$530.4	$ (432.3)

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PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31, 2011				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Net income	$957.7	$ 454.6	$ 415.5	$ (881.5)	$ 946.3
Other comprehensive (loss) income, net of income taxes:					
Net change in unrealized (losses) gains on available-for-sale securities (net of $3.9 tax benefit)					
Unrealized holding (losses) gains on available-for-sale securities	(6.0)	—	0.2	—	(5.8)
Less: Reclassification for realized gains included in net income	(0.9)	—	—	—	(0.9)
Net change in unrealized (losses) gains on available-for-sale securities	(6.9)	—	0.2	—	(6.7)
Net unrealized gains on cash flow hedges (net of $6.2 tax benefit)					
Increase in fair value of cash flow hedges	142.0	—	149.9	—	291.9
Less: Reclassification for realized gains included in net income	(241.9)	—	(9.1)	—	(251.0)
Net unrealized (losses) gains on cash flow hedges	(99.9)	—	140.8	—	40.9
Postretirement plans and workers' compensation obligations (net of $63.4 tax benefit)					
Prior service cost for the period	—	0.9	—	—	0.9
Net actuarial loss for the period	—	(148.6)	(1.5)	—	(150.1)
Amortization of actuarial loss and prior service cost	—	39.4	1.1	—	40.5
Postretirement plan and workers' compensation obligations	—	(108.3)	(0.4)	—	(108.7)
Other comprehensive income from investment in subsidiaries	32.3	—	—	(32.3)	—
Other comprehensive (loss) income, net of income taxes	(74.5)	(108.3)	140.6	(32.3)	(74.5)
Comprehensive income	883.2	346.3	556.1	(913.8)	871.8
Less: Comprehensive loss attributable to noncontrolling interests	—	—	(11.4)	—	(11.4)
Comprehensive income attributable to common stockholders	$883.2	$ 346.3	$ 567.5	$ (913.8)	$ 883.2

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31, 2010				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(Dollars in millions)				
Net income	$774.0	$393.1	$ 462.1	$ (827.0)	$ 802.2
Other comprehensive income (loss), net of income taxes:					
Net unrealized gains (losses) on cash flow hedges (net of $129.5 tax provision)					
Increase (decrease) in fair value of cash flow hedges	408.2	13.2	(191.5)	—	229.9
Less: Reclassification for realized gains included in net income	(85.8)	(7.0)	(9.6)	—	(102.4)
Net unrealized gains (losses) on cash flow hedges	322.4	6.2	(201.1)	—	127.5
Postretirement plans and workers' compensation obligations (net of $2.1 tax benefit)					
Prior service credit for the period	—	(4.9)	—	—	(4.9)
Net actuarial loss for the period	—	(40.9)	(0.4)	—	(41.3)
Amortization of actuarial loss and prior service cost	—	33.3	1.0	—	34.3
Postretirement plan and workers' compensation obligations	—	(12.5)	0.6	—	(11.9)
Other comprehensive loss from investment in subsidiaries	(206.8)	—	—	206.8	—
Other comprehensive income (loss), net of income taxes	115.6	(6.3)	(200.5)	206.8	115.6
Comprehensive income	889.6	386.8	261.6	(620.2)	917.8
Less: Comprehensive income attributable to noncontrolling interests	—	—	28.2	—	28.2
Comprehensive income attributable to common stockholders	$889.6	$386.8	$ 233.4	$ (620.2)	$ 889.6

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING BALANCE SHEETS

	December 31, 2012				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Reclassifications/ Eliminations	Consolidated
	(Dollars in millions)				
Assets					
Current assets					
Cash and cash equivalents	$269.6	$ 0.3	$ 288.9	$ —	$ 558.8
Accounts receivable, net	3.6	5.0	729.2	—	737.8
Inventories	—	271.4	277.0	—	548.4
Assets from coal trading activities, net	—	87.5	—	(35.1)	52.4
Deferred income taxes	—	57.3	2.3	(3.2)	56.4
Other current assets	275.0	—	354.6	(7.9)	621.7
Total current assets	548.2	421.5	1,652.0	(46.2)	2,575.5
Property, plant, equipment and mine development, net	—	5,120.8	6,680.9	—	11,801.7
Investments and other assets	9,524.7	—	1,037.0	(9,129.9)	1,431.8
Total assets	$10,072.9	$ 5,542.3	$ 9,369.9	$ (9,176.1)	$ 15,809.0
Liabilities and Stockholders' Equity					
Current liabilities					
Current maturities of long-term debt	$—	$ —	$ 47.8	$ —	$ 47.8
Payables to (receivables from) affiliates, net	2,309.3	(2,904.4)	595.1	—	—
Liabilities from coal trading activities, net	—	4.0	50.5	(35.1)	19.4
Deferred income taxes	3.2	—	—	(3.2)	—
Accounts payable and accrued expenses	63.3	595.0	956.5	(7.9)	1,606.9
Total current liabilities	2,375.8	(2,305.4)	1,649.9	(46.2)	1,674.1
Long-term debt, less current maturities	6,114.5	6.6	84.0	—	6,205.1
Deferred income taxes	43.2	142.0	392.1	—	577.3
Notes payable to (receivables from) affiliates, net	(3,421.3)	(1,100.4)	4,521.7	—	—
Other noncurrent liabilities	55.8	1,893.9	464.0	—	2,413.7
Total liabilities	5,168.0	(1,363.3)	7,111.7	(46.2)	10,870.2
Peabody Energy Corporation's stockholders' equity	4,904.9	6,905.6	2,224.3	(9,129.9)	4,904.9
Noncontrolling interests	—	—	33.9	—	33.9
Total stockholders' equity	4,904.9	6,905.6	2,258.2	(9,129.9)	4,938.8
Total liabilities and stockholders' equity	$10,072.9	$ 5,542.3	$ 9,369.9	$ (9,176.1)	$ 15,809.0

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING BALANCE SHEETS

	December 31, 2011				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Reclassifications/ Eliminations	Consolidated
		(Dollars in millions)			
Assets					
Current assets					
Cash and cash equivalents	$283.2	$0.8	$ 515.1	$ —	$ 799.1
Accounts receivable, net	5.3	100.8	816.4	—	922.5
Inventories	—	218.1	226.3	—	444.4
Assets from coal trading activities, net	—	14.9	29.7	—	44.6
Deferred income taxes	—	48.0	—	(20.7)	27.3
Other current assets	305.1	100.7	362.2	—	768.0
Total current assets	593.6	483.3	1,949.7	(20.7)	3,005.9
Property, plant, equipment and mine development, net	—	4,797.7	6,453.9	—	11,251.6
Investments and other assets	10,300.8	310.8	1,496.1	(9,632.2)	2,475.5
Total assets	$10,894.4	$5,591.8	$ 9,899.7	$ (9,652.9)	$ 16,733.0
Liabilities and Stockholders' Equity					
Current liabilities					
Current maturities of long-term debt	$62.5	$—	$ 38.6	$ —	$ 101.1
Payables to (receivables from) affiliates, net	2,417.8	(2,529.1)	111.3	—	—
Liabilities from coal trading activities, net	—	4.2	6.1	—	10.3
Deferred income taxes	11.6	—	9.1	(20.7)	—
Accounts payable and accrued expenses	69.4	868.8	774.1	—	1,712.3
Total current liabilities	2,561.3	(1,656.1)	939.2	(20.7)	1,823.7
Long-term debt, less current maturities	6,428.8	—	127.6	—	6,556.4
Deferred income taxes	76.0	95.3	351.9	—	523.2
Notes payable to (receivables from) affiliates, net	(3,720.0)	(981.5)	4,701.5	—	—
Other noncurrent liabilities	63.2	1,923.6	327.1	—	2,313.9
Total liabilities	5,409.3	(618.7)	6,447.3	(20.7)	11,217.2
Peabody Energy Corporation's stockholders' equity	5,485.1	6,210.5	3,421.7	(9,632.2)	5,485.1
Noncontrolling interests	—	—	30.7	—	30.7
Total stockholders' equity	5,485.1	6,210.5	3,452.4	(9,632.2)	5,515.8
Total liabilities and stockholders' equity	$10,894.4	$5,591.8	$ 9,899.7	$ (9,652.9)	$ 16,733.0

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2012			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
		(Dollars in millions)		
Cash Flows From Operating Activities				
Net cash provided by (used in) continuing operations	$372.0	$1,390.3	$(162.5)	$1,599.8
Net cash used in discontinued operations	(3.4)	(11.6)	(69.7)	(84.7)
Net cash provided by (used in) operating activities	368.6	1,378.7	(232.2)	1,515.1
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	—	(237.4)	(748.6)	(986.0)
Changes in accrued expenses related to capital expenditures	—	3.1	101.6	104.7
Federal coal lease expenditures	—	(276.5)	—	(276.5)
Investment in Prairie State Energy Campus	—	(10.7)	—	(10.7)
Proceeds from disposal of assets, net of notes receivable	—	70.1	77.8	147.9
Purchases of debt and equity securities	—	—	(46.7)	(46.7)
Proceeds from sales of debt and equity securities	—	—	46.4	46.4
Purchases of short-term investments	—	—	(4.8)	(4.8)
Contributions to joint ventures	—	—	(824.0)	(824.0)
Distributions from joint ventures	—	—	823.0	823.0
Advances to related parties	—	—	(148.0)	(148.0)
Repayment of loans from related parties	—	—	110.8	110.8
Other, net	—	(6.2)	—	(6.2)
Net cash used in continuing operations	—	(457.6)	(612.5)	(1,070.1)
Net cash used in discontinued operations	—	(1.1)	(20.9)	(22.0)
Net cash used in investing activities	—	(458.7)	(633.4)	(1,092.1)
Cash Flows From Financing Activities				
Repayments of long-term debt	(379.0)	(0.4)	(36.4)	(415.8)
Proceeds from long-term debt	—	—	0.8	0.8
Payment of debt issuance costs	(6.9)	—	—	(6.9)
Dividends paid	(91.9)	—	—	(91.9)
Common stock repurchase	(99.9)	—	—	(99.9)
Repurchase of employee common stock relinquished for tax withholding	(8.4)	—	—	(8.4)
Excess tax benefits related to share-based compensation	8.3	—	—	8.3
Acquisition of MCG Coal Holdings Pty Ltd noncontrolling interests	—	—	(49.8)	(49.8)
Other, net	9.4	(7.5)	(1.6)	0.3
Transactions with affiliates, net	186.2	(912.6)	726.4	—
Net cash (used in) provided by financing activities	(382.2)	(920.5)	639.4	(663.3)
Net change in cash and cash equivalents	(13.6)	(0.5)	(226.2)	(240.3)
Cash and cash equivalents at beginning of year	283.2	0.8	515.1	799.1
Cash and cash equivalents at end of year	$269.6	$0.3	$288.9	$558.8

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2011			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
		(Dollars in millions)		
Cash Flows From Operating Activities				
Net cash provided by continuing operations	$28.9	$1,513.7	$109.5	$1,652.1
Net cash provided by (used in) discontinued operations	4.4	(0.8)	(22.5)	(18.9)
Net provided by operating activities	33.3	1,512.9	87.0	1,633.2
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	—	(350.4)	(497.0)	(847.4)
Changes in accrued expenses related to capital expenditures	—	—	51.2	51.2
Federal coal lease expenditures	—	(42.4)	—	(42.4)
Investment in Prairie State Energy Campus	—	(36.2)	—	(36.2)
Proceeds from disposal of assets, net of notes receivable	—	34.1	6.0	40.1
Investments in equity affiliates and joint ventures	—	(2.0)	(37.7)	(39.7)
Purchases of debt and equity securities	—	(103.6)	(44.1)	(147.7)
Proceeds from sales of debt and equity securities	—	47.0	57.6	104.6
Purchases of short-term investments	(75.0)	—	(25.0)	(100.0)
Maturity of short-term investments	75.0	—	25.0	100.0
Acquisition of Macarthur Coal Limited, net of cash acquired	—	—	(2,756.7)	(2,756.7)
Contributions to joint ventures	—	—	(145.4)	(145.4)
Distributions from joint ventures	—	—	128.6	128.6
Advances to related parties	—	—	(371.3)	(371.3)
Repayment of loan from related parties	—	—	331.7	331.7
Other, net	—	(6.5)	(0.1)	(6.6)
Net cash used in continuing operations	—	(460.0)	(3,277.2)	(3,737.2)
Net cash used in discontinued operations	—	(8.3)	(62.3)	(70.6)
Net cash used in investing activities	—	(468.3)	(3,339.5)	(3,807.8)
Cash Flows From Financing Activities				
Repayments of long-term debt	(243.1)	—	(20.8)	(263.9)
Proceeds from long-term debt	4,100.0	—	1.4	4,101.4
Payment of debt issuance costs	(61.5)	—	—	(61.5)
Dividends paid	(92.1)	—	—	(92.1)
Repurchase of employee common stock relinquished for tax withholding	(18.7)	—	—	(18.7)
Excess tax benefits related to share-based compensation	8.1	—	—	8.1
Acquisition of PEAMCoal Pty Ltd noncontrolling interests	(11.1)	11.1	(1,994.8)	(1,994.8)
Other, net	11.1	(12.0)	0.9	—
Transactions with affiliates, net	(4,346.6)	(1,048.1)	5,394.7	—
Net cash (used in) provided by financing activities	(653.9)	(1,049.0)	3,381.4	1,678.5
Net change in cash and cash equivalents	(620.6)	(4.4)	128.9	(496.1)

Cash and cash equivalents at beginning of year	903.8	5.2	386.2	1,295.2
Cash and cash equivalents at end of year	$283.2	$0.8	$515.1	$799.1

PEABODY ENERGY CORPORATION
SUPPLEMENTAL CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2010			
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
		(Dollars in millions)		
Cash Flows From Operating Activities				
Net cash (used in) provided by continuing operations	$(126.4)	$1,078.4	$152.5	$1,104.5
Net cash (used in) provided by discontinued operations	(14.2)	9.8	(13.0)	(17.4)
Net cash (used in) provided by operating activities	(140.6)	1,088.2	139.5	1,087.1
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	—	(402.6)	(143.4)	(546.0)
Investment in Prairie State Energy Campus	—	(76.0)	—	(76.0)
Proceeds from disposal of assets, net of notes receivable	—	14.0	5.1	19.1
Investments in equity affiliates and joint ventures	—	(15.0)	(3.8)	(18.8)
Purchases of debt and equity securities	—	—	(74.6)	(74.6)
Proceeds from sales of debt and equity securities	—	—	12.4	12.4
Other, net	—	(8.7)	(0.1)	(8.8)
Net cash used in continuing operations	—	(488.3)	(204.4)	(692.7)
Net cash used in discontinued operations	—	(1.8)	(9.1)	(10.9)
Net cash used in investing activities	—	(490.1)	(213.5)	(703.6)
Cash Flows From Financing Activities				
Repayments of long-term debt	(1,146.8)	—	(20.5)	(1,167.3)
Proceeds from long-term debt	1,150.0	—	—	1,150.0
Payment of debt issuance costs	(32.2)	—	—	(32.2)
Dividends paid	(79.4)	—	—	(79.4)
Repurchase of employee common stock relinquished for tax withholding	(13.5)	—	—	(13.5)
Excess tax benefits related to share-based compensation	51.0	—	—	51.0
Other, net	22.3	(5.9)	(2.1)	14.3
Transactions with affiliates, net	724.6	(587.2)	(137.4)	—
Net cash provided by (used in) financing activities	676.0	(593.1)	(160.0)	(77.1)
Net change in cash and cash equivalents	535.4	5.0	(234.0)	306.4
Cash and cash equivalents at beginning of year	368.4	0.2	620.2	988.8
Cash and cash equivalents at end of year	$903.8	$5.2	$386.2	$1,295.2

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PEABODY ENERGY CORPORATION
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[1]	Other	Balance at End of Period
	(Dollars in millions)				
Year Ended December 31, 2012					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$21.3	$2.9	$ (9.0) [2]	$0.1 [3]	$15.3
Reserve for materials and supplies	6.5	13.7	(4.2)	—	16.0
Allowance for doubtful accounts	17.0	(0.5)	(0.7)	(2.1) [4]	13.7
Tax valuation allowances	79.8	521.5	(77.0) [5]	957.5 [6]	1,481.8
Year Ended December 31, 2011					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$19.9	$1.8	$ (0.1)	$(0.3) [3]	$21.3
Reserve for materials and supplies	6.2	3.7	(3.4)	—	6.5
Allowance for doubtful accounts	30.3	(3.7)	(0.4)	(9.2) [4]	17.0
Tax valuation allowances	65.0	15.4	—	(0.6)	79.8
Year Ended December 31, 2010					
Reserves deducted from asset accounts:					
Advance royalty recoupment reserve	$17.2	$1.9	$ (0.2)	$1.0 [3]	$19.9
Reserve for materials and supplies	6.2	0.9	(0.9)	—	6.2
Allowance for doubtful accounts	18.3	26.7	(6.9)	(7.8) [4]	30.3
Tax valuation allowances	87.2	(28.7)	—	6.5	65.0

(1) Reserves utilized, unless otherwise indicated.
(2) Deductions to advance royalty recoupment reserve represents the termination of federal and state leases.
(3) Balances transferred (to) from other accounts or reserves recorded as part of a property transaction or acquisition.
(4) Represents subsequent recovery of receivable amounts previously reserved.
(5) Deductions include write-off of loss carryforwards and reversal of related valuation allowances.
(6) Includes changes to valuation allowances primarily related to deferred tax assets acquired in business combinations and initial deferred tax assets resulting from the newly created minerals resource rent tax in Australia.

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EXHIBIT INDEX

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

Exhibit No.	Description of Exhibit
3.1	Third Amended and Restated Certificate of Incorporation of the Registrant, as amended (Incorporated by reference to Exhibit 3.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
3.2	Amended and Restated By-Laws of the Registrant (Incorporated by reference to Exhibit 3.1 of the Registrant's Current Report on Form 8-K, filed September 16, 2008).
4.1	Specimen of stock certificate representing the Registrant's common stock, $.01 par value (Incorporated by reference to Exhibit 4.13 to Amendment No. 4 to the Registrant's Form S-1 Registration Statement No. 333-55412, filed May 1, 2001).
4.2	Indenture, dated as of March 19, 2004, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.3	Subordinated Indenture, dated as of December 20, 2006, between the Registrant and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K, filed December 20, 2006).
4.4	Indenture, dated as of November 15, 2011, among Peabody, the Guarantors named therein and U.S. Bank National Association, as trustee, governing the 6.00% Senior Notes Due 2018 and 6.25% Senior Notes Due 2021 (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K, filed November 17, 2011). Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of the Registrant. The Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon its request.
10.1	Credit Agreement, dated as of June 18, 2010, by and among the Registrant, Peabody Holland B.V., Bank of America, N.A., as administrative agent, swing line lender and L/C issuer, and Banc of America Securities LLC, Citigroup Global Markets, Inc. and HSBC Securities (USA) Inc., as joint lead arrangers and joint book managers, and the lenders named therein (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed on June 24, 2010).
10.2	Amendment No. 1 to Credit Agreement, dated as of October 20, 2011, made by and among the Registrant, Peabody Holland B.V., the lenders named therein and Bank of America, N.A., as administrative agent (Incorporated by reference to Exhibit 10.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.3	Amendment No. 2 to Credit Agreement, dated as of November 16, 2012, made by and among the Registrant, Peabody Holland B.V., the lenders named therein and Bank of America, N.A., as administrative agent (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 19, 2012).

10.4	Credit Agreement, dated as of October 28, 2011, among Peabody Energy Corporation, as borrower, Bank of America, N.A., as administrative agent, Merrill Lynch, Pierce, Fenner & Smith Incorporated, UBS Securities LLC, Morgan Stanley Senior Funding, Inc., Citigroup Global Markets Inc., HSBC Bank (USA) N.A. and RBS Securities Inc., as joint lead arrangers and joint book managers, and the other lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed November 2, 2011).
10.5	Amendment No. 1 to Credit Agreement, dated as of November 16, 2012, made by and among the Registrant, the lenders named therein and Bank of America, N.A., as administrative agent (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on November 19, 2012).
10.6	Third Amended and Restated Receivables Purchase Agreement, dated as of January 25, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed January 27, 2010).

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Exhibit No.	Description of Exhibit
10.7	First Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of March 1, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.2 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.8	Second Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of May 11, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed May 17, 2010).
10.9	Third Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of September 16, 2010, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.10	Fourth Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of May 10, 2011, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.2 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
10.11	Fifth Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of October 24, 2011, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.3 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.12	Sixth Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of May 8, 2012, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents

	listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.4 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.13	Seventh Amendment to Third Amended and Restated Receivables Purchase Agreement, dated as of September 26, 2012, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Related Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.5 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.14	Federal Coal Lease WYW0321779: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.3 of the Registrant's Form S-4 Registration Statement No. 333-59073).
10.15	Federal Coal Lease WYW119554: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.4 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.16	Federal Coal Lease WYW5036: Rawhide Mine (Incorporated by reference to Exhibit 10.5 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.17	Federal Coal Lease WYW3397: Caballo Mine (Incorporated by reference to Exhibit 10.6 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).

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Exhibit No.	Description of Exhibit
10.18	Federal Coal Lease WYW83394: Caballo Mine (Incorporated by reference to Exhibit 10.7 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.19	Federal Coal Lease WYW136142 (Incorporated by reference to Exhibit 10.8 of Amendment No. 1 to the Registrant's Form S-4 Registration Statement No. 333-59073, filed September 8, 1998).
10.20	Royalty Prepayment Agreement by and among Peabody Natural Resources Company, Gallo Finance Company and Chaco Energy Company, dated September 30, 1998 (Incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
10.21	Federal Coal Lease WYW154001: North Antelope Rochelle South (Incorporated by reference to Exhibit 10.68 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).
10.22	Federal Coal Lease WYW150210: North Antelope Rochelle Mine (Incorporated by reference to Exhibit 10.8 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
10.23	Federal Coal Lease WYW151134 effective May 1, 2005: West Roundup (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10.24†	Federal Coal Lease Readjustment WYW78663: Caballo.
10.25†	Transfer by Assignment and Assumption of Federal Coal Lease WYW172657: Caballo West.
10.26†	Federal Coal Lease WYW176095: Porcupine South.
10.27†	Federal Coal Lease WYW173408: North Porcupine.
10.28†	Federal Coal Lease WYW172413: School Creek.
10.29	Separation Agreement, Plan of Reorganization and Distribution, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.30	Tax Separation Agreement, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.31	Coal Act Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.32	NBCWA Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.33	

	Salaried Employee Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.5 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.34	Coal Supply Agreement, dated October 22, 2007, between Patriot Coal Sales LLC and COALSALES II, LLC (Incorporated by reference to Exhibit 10.6 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.35*	1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 4.9 of the Registrant's Form S-8 Registration Statement No. 333-105456, filed May 21, 2003).
10.36*	Amendment to the 1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K, filed October 17, 2007).
10.37*	Amendment No. 2 to the 1998 Stock Purchase and Option Plan for Key Employees of the Registrant (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed December 11, 2007).
10.38*	Form of Non-Qualified Stock Option Agreement under the Registrant's 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.15 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).
10.39*	Form of Amendment to Non-Qualified Stock Option Agreement under the Registrant's 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.16 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

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Exhibit No.	Description of Exhibit
10.40*	Form of Amendment, dated as of June 15, 2004, to Non-Qualified Stock Option Agreement under the Registrant's 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.65 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.41*	Form of Incentive Stock Option Agreement under the Registrant's 1998 Stock Purchase and Option Plan for Key Employees (Incorporated by reference to Exhibit 10.17 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).
10.42*	Long-Term Equity Incentive Plan of the Registrant (Incorporated by reference to Exhibit 99.2 of the Registrant's Form S-8 Registration Statement No. 333-61406, filed May 22, 2001).
10.43*	Amendment to the Registrant's 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed October 17, 2007).
10.44*	Form of Non-Qualified Stock Option Agreement under the Registrant's 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).
10.45*	Form of Performance Unit Award Agreement under the Registrant's 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.19 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).
10.46*	Form of Non-Qualified Stock Option Agreement for Outside Directors under the Registrant's 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed December 14, 2005).
10.47*	Form of Restricted Stock Award Agreement for Outside Directors under the Registrant's 2001 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K, filed December 14, 2005).
10.48*	Equity Incentive Plan for Non-Employee Directors of the Registrant (Incorporated by reference to Exhibit 99.3 of the Registrant's Form S-8 Registration Statement No. 333-61406, filed May 22, 2001).
10.49*	Form of Non-Qualified Stock Option Agreement under the Registrant's Equity Incentive Plan for Non-Employee Directors (Incorporated by reference to Exhibit 10.20 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).
10.50*	The Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Annex A to the Registrant's Proxy Statement for the 2004 Annual Meeting of Stockholders, filed April 2, 2004).
10.51*	Amendment No. 1 to the Registrant's 2004 Long Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.67 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).
10.52*	Amendment No. 2 to the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed October 17, 2007).

10.53*	Amendment No. 3 to the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed October 17, 2007).
10.54*	Amendment No. 4 to the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed December 11, 2007).
10.55*	Form of Non-Qualified Stock Option Agreement under the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed January 7, 2005).
10.56*	Form of Performance Units Agreement under the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed January 7, 2005).
10.57*	Form of Performance Units Agreement under the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.36 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).
10.58*	Form of Performance Unit Award Agreement under the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).
10.59*	Form of Deferred Stock Units Agreement for Non-Employee Directors under the Registrant's 2004 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.43 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2010).
10.60*	Peabody Energy Corporation 2011 Long-Term Equity Incentive Plan (incorporated by reference to Appendix A of the Registrant's Proxy Statement, filed March 22, 2011).

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Exhibit No.	Description of Exhibit
10.61*	Form of Non-Qualified Stock Option Agreement under the Registrant's 2011 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.59 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.62*	Form of Performance Units Agreement under the Registrant's 2011 Long-Term Equity Incentive Plan. (Incorporated by reference to Exhibit 10.60 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.63*	Form of Restricted Stock Award Agreement under the Registrant's 2011 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.61 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.64*	Form of Deferred Stock Unit Agreement under the Registrant's 2011 Long-Term Equity Incentive Plan (Incorporated by reference to Exhibit 10.62 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.65*	2009 Amendment entered into effective December 31, 2009 to the Stock Grant Agreement dated as of October 1, 2003 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.45 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.66*	2009 Amendment entered into effective December 31, 2009 to the Non-Qualified Stock Option Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.46 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.67*	2009 Amendment entered into effective December 31, 2009 to the Non-Qualified Stock Option Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.47 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.68*	2009 Amendment entered into effective December 31, 2009 to the Performance Units Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.48 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.69*	2009 Amendment entered into effective December 31, 2009 to the Performance Units Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.49 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.70*	2010 Amendment entered into effective March 17, 2010, to the 2008 Performance Units Award Agreement dated January 2, 2008 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.3 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.71*	2010 Amendment entered into effective March 17, 2010, to the 2009 Performance Units Award Agreement dated January 5, 2009 between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.4 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010).
10.72*	Amended and Restated Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.44 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
10.73*	Amendment to the Amended and Restated Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.51 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.74*	Amended and Restated Australian Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.45 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
10.75*	

	Amendment to the Amended and Restated Australian Employee Stock Purchase Plan of the Registrant (Incorporated by reference to Exhibit 10.53 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009).
10.76*	Management Annual Incentive Compensation Plan (Incorporated by reference to Exhibit 10.61 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).
10.77*	2008 Management Annual Incentive Compensation Plan (Incorporated by reference to Appendix B to the Registrant's Proxy Statement for the 2008 Annual Meeting of Shareholders, filed March 27, 2008).
10.78*	The Registrant's Deferred Compensation Plan (Incorporated by reference to Exhibit 10.30 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.79*	First Amendment to the Registrant's Deferred Compensation Plan (Incorporated by reference to Exhibit 10.49 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).

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Exhibit No.	Description of Exhibit
10.80*	Letter Agreement, dated as of March 1, 2005, by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed March 4, 2005).
10.81*	Restated Employment Agreement effective December 31, 2009 by and between the Registrant and Gregory H. Boyce (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed December 24, 2009).
10.82*	Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Michael C. Crews (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed December 31, 2008).
10.83*	Letter Agreement, dated as of December 22, 2006, by and between the Registrant and Eric Ford (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed December 29, 2006).
10.84*	Form of Restricted Stock Agreement -- Exhibit A (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed December 29, 2006).
10.85*	Form of Restricted Stock Agreement -- Exhibit B (Incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K, filed December 29, 2006).
10.86*	Executive Service Agreement entered into on April 1, 2012 between Peabody Energy Australia Coal Pty Limited and Eric Ford (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 5, 2012).
10.87*	Restated Employment Agreement entered into as of December 31, 2008 by and between the Registrant and Sharon D. Fiehler (Incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K, filed December 31, 2008).
10.88*	Restated Employment Agreement entered into as of January 7, 2013 by and between the Registrant and Charles F. Meintjes. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K, filed January 10, 2013).
10.89*†	Form of Director and Executive Officer Indemnification Agreement between the Registrant and each of its directors and executive officers.
10.90*	Peabody Investments Corp. Supplemental Employee Retirement Account (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
21†	List of Subsidiaries.
23†	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31.1†	Certification of periodic financial report by the Registrant's Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of periodic financial report by the Registrant's Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1†	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Executive Officer.
32.2†	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Financial Officer.
95†	Mine Safety Disclosure required by Item 104 of Regulation S-K.
101†	Interactive Data File (Form 10-K for the year ended December 31, 2012 filed in XBRL). The financial information contained in the XBRL-related documents is “unaudited” and “unreviewed.”

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

† Filed herewith.