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.

Represented 2012 tons sold from our Willow Lake Mine, which commenced closure activities in November 2012.

(3) 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.

We own a 50.0% equity interest in Middlemount Coal Pty Ltd., which owns the Middlemount Mine. Because that

(5) 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.

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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.

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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]		
		Owned	Leased	Total
Operating Regions	Locations	Tons	Tons	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]			
Geographic Region / Mining Complex	Year Ended Dec. 31, 2012	Year Ended Dec. 31, 2011	Year Ended Dec. 31, 2010	Type of Coal	<1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	As Received Btu per pound [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				
Coal Seam Location	Total Tons Assigned	Unassigned	Proven and Probable Reserves	Proven	Probable	Total Tons Assigned	Unassigned	Proven and Probable 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					