PEABODY ENERGY CORP
Form 10-K
February 21, 2014
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2013
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 þ 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 þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

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

Aggregate market value of the voting stock held by non-affiliates (shareholders who are not directors or executive officers) of the Registrant, calculated using the closing price on June 30, 2013: Common Stock, par value $0.01 per share, $3.9 billion.

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of February 14, 2014: Common Stock, par value $0.01 per share, 271,298,814 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 2014 Annual Meeting of Shareholders (the Company's 2014 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,” "forecast," “project,” “should,” “estimate,” “plan,” "outlook" or otl similar words to identify 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, site access, operational risks and new technologies 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, changes in income tax regulations, sales-related royalties or other regulatory taxes and changes in derivatives laws and regulations;
- 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 2,204.62 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. 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, India, Indonesia 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 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 PEA-PCI (formerly Macarthur Coal Limited), 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 performance and marketing;
2) Continue to target cost improvements across our global platform to improve our competitive position;
3) Capitalize on organic growth and development opportunities as warranted by global coal market conditions;
4) Expand our presence in high-growth global markets, particularly in Asia; and
5) Advance our new global coal advocacy initiative aimed at improving energy policies around the world.

In response to the challenged environment continuing to be faced by global coal markets in 2013, we advanced multiple projects focused on holding our strong competitive position in the market segments in which we operate. Such advancements included completing owner-operator conversions at the Wilpinjong, Millennium, Wambo Open-Cut and Middlemount mines in Australia; realizing productivity improvements at PEA-PCI operations in Australia as a result of optimization and remediation efforts completed in the prior year; continuing equipment and facility upgrades at our Metropolitan Mine in Australia; and continuing our ongoing cost containment initiatives across our global platform.

Moving forward into 2014, we expect to maintain a disciplined approach to capital spending as we continue to navigate through the near-term challenges in global coal markets. Planned capital and operational projects for 2014 are mainly focused on driving operational improvements and preserving the productive capacity of our existing mining platform. Such projects include completing the commissioning and post start-up modifications of longwall top coal caving technology at our North Goonyella Mine in Australia, converting our Moorvale Mine in Australia to owner-operator status and advancing development of our planned Gateway North Mine in the U.S.

We will continue to explore opportunities to extend our presence in the Asia-Pacific region through joint mine development partnerships or trading agreements 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 27. "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, 2013. Also shown are the primary ports that 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 sale 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. The impact of those higher transportation costs on delivered costs to our customers is generally offset by lower coal prices.

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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, semi-hard coking, semi-soft and low volatile pulverized coal injection (LV PCI) coals. LV PCI coal is generally used by steel producers as a partial replacement for coke made from coking coal.

Our Australian Mining segment operations are primarily export focused with customers spread across several countries, with a portion of our coal being sold within Australia. 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, transportation costs, 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 2013.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Transport Method	2013 Tons Sold (In millions)
Western U.S. Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	110.9
Rawhide	Wyoming	S	D, T/S	T	R	14.2
Caballo	Wyoming	S	D, T/S	T	R	9.0
El Segundo	New Mexico	S	D, D/L, T/S	T	R	8.4
Kayenta	Arizona	S	DL, T/S	T	R	7.9
Twentymile	Colorado	U	LW	T	R, T	7.2
Lee Ranch	New Mexico	S	T/S	T	R	0.1
Other (1)	—	—	—	—	—	1.1
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	T, R	8.2
Francisco Underground	Indiana	U	CM	T	R	2.9
Gateway	Illinois	U	CM	T	T, R, R/B, T/B	2.8
Somerville Central	Indiana	S	DL, D, T/S	T	R, T/R, T/B	2.7
Wild Boar	Indiana	S	D, T/S	T	T, R, R/B, T/B	2.0
Cottage Grove	Illinois	S	D, T/S	T	T/B	1.9
Wildcat Hills Underground	Illinois	U	CM	T	T/B	1.6
Somerville North (2)	Indiana	S	D, T/S	T	T, R, T/R, T/B	1.5
Somerville South (2)	Indiana	S	D, T/S	T	T, R, T/R, T/B	1.5
Viking - Corning Pit (3)	Indiana	S	D, T/S	T	T, T/R	1.1
Other (1)	—	—	—	—	—	0.1
Australian Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	13.7
North Wambo Underground (2)	New South Wales	U	LW	T, P	R, EV	3.5
Millennium	Queensland	S	D, T/S	M, P	R, EV	3.4
Coppabella (4)	Queensland	S	DL, D, T/S	P	R, EV	3.1
Wambo Open-Cut (2)	New South Wales	S	T/S	T	R, EV	2.6
Burton *	Queensland	S	T/S	T, M	R, EV	2.1
Moorvale * (4)	Queensland	S	T/S	M, P	R, EV	2.1
North Goonyella	Queensland	U	LTCC	M	R, EV	1.7
Metropolitan	New South Wales	U	LW	M	R, EV	1.4
Eaglefield *	Queensland	S	T/S	M	R, EV	1.3
Middlemount (5)	Queensland	S	T/S	M, P	R, EV	—

Legend:

S	Surface Mine	R	Rail
		T	Truck

U	Underground Mine	R/B	Rail and Barge
DL	Dragline	T/B	Truck and Barge
D	Dozer/Casting	T/R	Truck and Rail
T/S	Truck and Shovel	EV	Export Vessel
LW	Longwall	T	Thermal/Steam
LTCC	Longwall Top Coal Caving	M	Metallurgical
CM	Continuous Miner	P	Pulverized Coal Injection
*	Mine is operated by a contract miner		

(1) "Other" in Western and Midwestern U.S. Mining primarily consists of purchased coal used to satisfy certain specific coal supply agreements.

(2) Represents our majority-owned mines in which there is an outside non-controlling ownership interest.

(3) Mine is expected to close in the first half of 2014.

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

(5) We own a 50.0% equity interest in Middlemount Coal Pty Ltd., which owns the Middlemount Mine. Because that entity is accounted for as an unconsolidated equity affiliate, 2013 tons sold from that mine have been excluded from the table above.

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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. From time to time and where possible, our Trading and Brokerage segment may enter into financial derivative contract positions offsetting certain coal purchase and sale contracts included in our portfolio in an effort to reduce market price risk and secure a margin on forecasted transactions. Our Trading and Brokerage segment also provides transportation-related services, including economic hedging, in support of our coal trading strategy, as well as cash flow 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 the evaluation of Btu Conversion projects.

Resource Management. As of December 31, 2013, we held approximately 8.3 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 LV PCI 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 2013. During the year ended December 31, 2013, the mine sold approximately 3 million tons of coal (on a 100% basis).

Paso Diablo Mine. We own a 48.37% noncontrolling interest in Carbones del Guasare S.A. (CdG), which previously operated the Paso Diablo Mine, a surface mining operation in northwestern Venezuela that produced thermal coal for export primarily to the U.S. and Europe. In the fourth quarter of 2013, the Venezuelan government, at the discretion of the Minister of Energy for the Republic of Venezuela, refused to act upon CdG's request for an extension or renewal of the underlying mining concession for the Paso Diablo Mine and the concession expired. The expiration of the concession triggered, by law, the extinguishment of the underlying mining rights that were granted to CdG and the transfer of all of the mining assets previously owned by CdG related to the mine to the Republic of Venezuela. In addition, these events converted an ongoing condition of force majeure under the one remaining coal sales contract we had for coal supplied from the Paso Diablo Mine into a permanent force majeure, resulting in the termination of the coal sales contract. We had previously fully impaired the carrying value of our equity investment in CdG in 2009. Accordingly, the expiration of CdG's mining concession did not impact our results of operations, financial condition or cash flows for the year ended December 31, 2013.

Singapore Joint Venture. We own a 50% interest in Sino-Pacific Coal Trading Corporation Pte. Ltd. (Sino-Pacific), a Singapore-based joint venture agreement with Shenhua Group Corporation Limited (Shenhua), a large-scale state-owned energy company headquartered in Beijing, China. The joint venture is intended to supply Shenhua's Chinese coal import demand with thermal coal. Sino-Pacific is expected to commence operations in 2014, subject to regulatory approvals.

Mongolia Joint Venture. We own a 50% interest in Peabody-Winsway Resources B.V., a joint venture agreement with Winsway Coking Coal Holdings Ltd. (Winsway), a Hong Kong stock exchange listed company in which we also own an equity interest. The joint venture holds several exploration licenses in Mongolia.

Export Facilities. We have a 37.5% interest in Dominion Terminal Associates, a partnership that operates a coal export terminal in Newport News, Virginia that exports both metallurgical and thermal coal primarily to European and Brazilian markets.

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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.

Clean Coal Technology. We continue to support clean coal technology development and other "green coal" initiatives seeking to reduce global atmospheric levels of carbon dioxide and other emissions. In China, we are the only non-Chinese equity partner in GreenGen, an integrated gasification combined cycle coal-fueled power plant near Tianjin, China that began electric generation for commercial consumption in 2012 and plans to utilize carbon capture and storage (CCS) in its next stage of development. We are also a founding member of the U.S.-China Energy Cooperation Program. In Australia, we have an ongoing commitment to the Australian COAL21 Fund, an industry effort to pursue a collection of low-carbon emission technologies in Australia, and are also a founding member of the Global Carbon Capture and Storage Institute, an international initiative hosted by the Australian government. In the U.S., we are a founding member of the FutureGen Alliance in Illinois and are presently developing the FutureGen 2.0 project. We are also a founding member of the Consortium for Clean Coal Utilization at Washington University in St. Louis in Missouri and the National Carbon Capture Center in Alabama.

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. Historically, the actuarially-determined reserves maintained by our captive insurance companies have provided adequate coverage of actual claims incurred.

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 and which typically include price reopener and/or extension provisions). A smaller portion of our sales are made on a shorter-term or a spot basis. Sales under long-term coal supply agreements comprised approximately 80%, 89% and 91% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2013, 2012 and 2011, respectively.

For the year ended December 31, 2013, we derived 25% of our total revenues from our five largest customers. Those five customers were supplied primarily from 46 coal supply agreements (excluding trading transactions) expiring at various times from 2014 to 2026. The contract contributing the greatest amount of annual revenue in 2013 was approximately $340 million, or approximately 5% of our 2013 total revenues, 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 tons of coal as of both January 1, 2014 and 2013. Contracts in backlog have remaining terms ranging from one to 14 years and represent approximately four years of production based on our 2013 production volume of 218.4 million tons. Approximately 77% of our backlog is expected to be filled beyond 2014.

U.S. Mining Operations. Revenues from our Western and Midwestern U.S. Mining segments, in aggregate, represented approximately 57%, 54% and 55% of our total revenue base for the years ended December 31, 2013, 2012 and 2011, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 84%, 85% and 89% 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.

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Australian Mining Operations. Revenues from our Australian Mining segment represented approximately 41%, 43% and 39% of our total revenue base for the years ended December 31, 2013, 2012 and 2011, respectively, during which periods the coal mining activities of that segment contributed respective amounts of 16%, 15% and 11% of our sales volumes from mining operations. Our production is primarily sold into the seaborne metallurgical and thermal markets, with a majority of those sales executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. Industry commercial practice, and our typical practice, is to negotiate pricing for those metallurgical and seaborne thermal coal contracts on a quarterly and annual basis, respectively, with a portion sold on a shorter-term basis.

Transportation

Methods of Distribution. Coal consumed in the U.S. is usually sold at the mine with transportation costs borne by the purchaser. Our Australian export coal is usually sold at the loading port, with purchasers paying ocean freight. Our U.S. export coal is more typically sold on a delivered basis into the unloading port, with us paying ocean freight. In each case, 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 continued to improve during 2013, as in the prior year.

We believe we have good relationships with U.S. and Australian rail carriers and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation coordinators. Refer to the table on page 5 in the foregoing "Mining Segments" section for a summary of transportation methods by mine.

Export Facilities. Our U.S. Mining operations exported approximately 2%, 3% and 3% of its tons sold for the years ended December 31, 2013, 2012 and 2011, respectively. 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. We are continuing to pursue access to U.S. west coast port facilities that will allow us to export our Powder River Basin coal products to serve demand in the Asian region.

Our Australian Mining operations sold approximately 75%, 77% and 74% of its tons into the seaborne coal markets for the years ended December 31, 2013, 2012 and 2011, respectively. We have generally secured our ability to transport coal in Australia 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 Condition 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).

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 that 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 in lieu of seeking other alternatives, it has been to take advantage of cost savings from larger volumes of purchases, benefit from long-term pricing for parts, 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.

While demand growth has outpaced supply in recent periods, market demand and lead times for certain OTR tires stabilized in 2013. We do not expect lead times or any supply constraints 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.

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Surface and underground mining equipment demand and lead times decreased substantially on a year-over-year basis in 2012 and remained lower in 2013 due to challenged market conditions experienced across several extractive industry sectors. This is consistent with a decline in our own near-term demand for such equipment as we have sought to defer new and early stage development projects, while continuing to evaluate the timing associated with such projects based on changes in global coal market demand. We continue to use our global leverage with major suppliers to either ensure security of supply to meet the requirements of our active projects or to delay deliveries when warranted by coal 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.

Technical Innovation

We continue to advance new technologies to maximize safety, including partnering with other companies and certain governmental agencies to pursue technologies that have the potential to improve our safety performance and provide better safety protection for employees. We are currently partnering with three of our mining equipment vendors to incorporate proximity detection systems on our continuous miners and proximity detection and video surveillance systems on our battery-powered coal haulage equipment, shuttle cars and section scoops at our U.S. underground mines. Additionally, we have installed and are testing a proximity detection system for large mining equipment and light vehicles at one of our Australian surface mines. We have also initiated a collaborative effort with certain vendors to identify and evaluate potential fatigue monitoring programs and technologies for our surface operations.

We 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 improve our operating performance and mining capabilities.

We seek to deploy the best mining technologies available based on the specific geologic conditions of each of our mining operations. For example, we commenced with the the commissioning of longwall top coal caving technology at our North Goonyella Mine in Australia in 2013, which technology we expect will be fully operational in 2014.

We leverage technology and data systems to enhance our operating and maintenance efforts through the integration of original equipment manufacturer systems, mobile technologies and automated reporting systems to provide an integrated, real time picture of of our mining operations and equipment performance. We continue to advance the use of 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.

We employ maintenance standards based on reliability-centered maintenance practices at all operations to increase equipment utilization and reduce maintenance and capital spending over time 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.

Competition

The markets in which we sell our coal are highly competitive. We compete directly with other coal producers and, with respect to our thermal coal products, indirectly with producers of other energy products that provide an alternative to coal use. We compete on the basis of coal quality and characteristics, delivered price, customer service and support and reliability of supply. Our principal U.S. direct competitors (listed alphabetically) are other large coal producers, including Alliance Resource Partners, Alpha Natural Resources, Inc., Arch Coal, Inc. and Cloud Peak Energy Inc., who collectively accounted for approximately 36% of total U.S. coal production in 2012 according to the National Mining Association's "2012 Coal Producer Survey," the most recent data publicly available as of February 21, 2014. Major international direct competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Glencore Xstrata PLC, Rio Tinto and Shenhua Group.

Demand for coal and the prices that we will be able to obtain for our coal are influenced by factors beyond our control, including global economic conditions, the 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. Metallurgical coal demand is also impacted by competing technologies used to make steel, some of which do not use coal as a manufacturing input.

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The use of thermal coal is further 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 reliably at a competitive price. The International Energy Agency (IEA) reported in its World Energy Outlook 2013 that coal's share of worldwide electric power generation mix was 41% in 2011. Alternative fuels to thermal coal include natural gas, fuel oil and nuclear, hydroelectric, wind, biomass and solar power sources.

Due to domestic growth in the use of hydraulic fracturing, natural gas is the most significant substitute to thermal coal for electricity generation in the U.S., and vice versa. The U.S. Energy Information Administration (EIA) reported in its February 2014 "Short-Term Energy Outlook" that, driven by a 36% increase in full year average U.S. natural gas prices during 2013, coal's share of U.S. electricity generation for all sectors increased from 37% in 2012 to 39% in 2013, while still falling short of the 42% level experienced in 2011. 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 a range of $2.75 to $3.00 per mmBtu and $3.50 to $3.75 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 of $4.17 per mmBtu in 2014 and correspondingly projects coal's share of U.S. electricity generation for all sectors to increase to 40% in that period.

Working Capital

We generally fund our working capital requirements through a combination of existing cash and cash equivalents and proceeds from the sale of our coal production to customers and our trading and brokerage activities. Our revolving credit facility (the 2013 Revolver) under our secured credit agreement entered into in 2013 (the 2013 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 Condition and Results of Operations" for additional information regarding working capital.

Employees

We had approximately 8,300 employees as of December 31, 2013, including approximately 5,900 hourly employees. Additional information on our employees and related labor relations matters is contained in Note 22. "Management - Labor Relations" to our consolidated financial statements, which information is incorporated herein by reference.

Executive Officers of the Company

Set forth below are the names, ages and 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 (1)	Position (2)
Gregory H. Boyce	59	Chairman and Chief Executive Officer, Director
Glenn L. Kellow	46	President and Chief Operating Officer
Michael C. Crews	46	Executive Vice President and Chief Financial Officer
Sharon D. Fiehler	57	Executive Vice President and Chief Administrative Officer
Eric Ford	59	Executive Vice President - Office of the Chief Executive Officer
Christopher J. Hagedorn	41	President - Asia and Trading
Jeane L. Hull	59	Executive Vice President and Chief Technical Officer
Charles F. Meintjes	51	President - Australia
Alexander C. Schoch	59	Executive Vice President Law, Chief Legal Officer and Secretary
Kemal Williamson	54	President - Americas

(1) As of February 14, 2014.

(2) As of December 31, 2013.

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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 of the Company in March 2005 and assumed the position of Chief Executive Officer in January 2006. He was President of the Company from October 2003 to December 2007 and was Chief Operating Officer of the Company from October 2003 to December 2005. He previously served as Chief Executive - Energy of Rio Tinto plc (an international natural resource company) from 2000 to 2003. Other prior positions include President and Chief Executive Officer of Kennecott Energy Company from 1994 to 1999 and President of Kennecott Minerals Company from 1993 to 1994. He has extensive engineering and operating experience with Kennecott. Mr. Boyce serves on the board of directors of Marathon Oil Corporation and Monsanto Company. He is Chairman of the Coal Industry Advisory Board of the International Energy Agency and is a former Chairman of the National Mining Association. He serves on the Board of Directors of the U.S.-China Business Council, and is a member of The Business Council, Business Roundtable and the National Coal Council. In addition, Mr. Boyce is a member of the Board of Trustees of Washington University in St. Louis and the Advisory Council of the University of Arizona’s Department of Mining and Geological Engineering. He also is President of the Board for Variety - The Children’s Charity of St. Louis and is a member of the Board of Commissioners for the St. Louis Science Center.

Glenn L. Kellow was named our President and Chief Operating Officer in August 2013. He has executive responsibility for all aspects of our global operations including safety, production, sales and marketing, environmental, productivity improvement, engineering and planning. Mr. Kellow has extensive experience in the global resource industry, where he has served in multiple executive, operational and financial roles in coal and other commodities in the United States, Australia and South America. From 1985 to 2013, Mr. Kellow served in a number of roles with BHP Billiton, the world’s largest mining company, including senior appointments as President, Aluminum and Nickel (2012-2013), President, Stainless Steel Materials (2010-2012), President and Chief Operating Officer, New Mexico Coal (2007-2010), and Chief Financial Officer, Base Metals (2003-2007). He is a former director of the World Coal Association and the National Mining Association and was the Chairman of Worsley Alumina (Australia), Chairman of Mozal (Mozambique) and Vice Chairman of the Nickel Institute. Mr. Kellow is a graduate of the advanced management program at the University of Pennsylvania’s Wharton School of Business and holds a master’s degree in business administration and a bachelor’s degree in commerce from the University of Newcastle.

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 and is a member of the advisory board of Washington University's Wells Fargo Advisors Center for Financial and Accounting Research. 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. Prior to joining us, she 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; and a member of the Board of Directors of Junior Achievement of Greater St. Louis. 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.

Eric Ford was named Executive Vice President, Office of the Chief Executive Officer, in August 2013. He retired from Peabody on January 31, 2014. Mr. Ford served as Chairman - Australia from October 2012 to August 2013, 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 IEA.

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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. Mr. 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, and on the following Boards of Directors: the National Blues Museum, St. Louis, Missouri; Safe Connections, St. Louis, Missouri; and Case Western Reserve University Law Alumni Association, Cleveland, Ohio.

Kemal Williamson was named our President - Americas in October 2012. He has executive responsibility for our U.S. operating platform 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.

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Regulatory Matters — U.S.

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

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

Mine Safety and Health

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

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

MSHA has 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 by SEC regulations.

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.

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.

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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 SMCRA Abandoned Mine Land Fund 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 has been in the process of developing a “stream protection rule,” which could result in changes to mining operations under the SMCRA program. The OSM has projected that it will issue a proposed stream protection rule in 2014. Other rulemaking proceedings have been proposed or are being considered by the OSM. Notably, the Proposed Rule for Cost Recovery for Permit Processing, Administration and Enforcement was published in March 2013. If finalized as proposed, it will result in minor cost increases at our mine operations on tribal lands in Arizona. Additionally, the OSM is working on a Coal Combustion Residues rulemaking for minefill operations. The agency has projected it may publish a proposed rule by May 2014. These OSM rulemakings and others could have a direct impact on our operations.

Clean Air Act. The Clean Air Act, enacted in 1970, and comparable state and tribal laws that regulate air emissions 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 U.S. Environmental Protection Agency (EPA) in 2009 adopted revised rules to add more stringent PM emissions limits for coal preparation and processing plants constructed or modified after April 28, 2008. Since 2011, the EPA has required underground coal mines to report on their greenhouse gas emissions.

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 (NSPS), Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and New Source Review. In addition, in recent years the U.S. EPA has adopted more stringent NAAQS for PM, nitrogen oxide and sulfur dioxide. The EPA is expected to propose a more stringent ozone standard from the current standard. The Sierra Club and others requested the U.S. District Court for the Northern District of California on January 21, 2014 to order the EPA to propose a new ozone NAAQS by December 1, 2014 and issue a final rule by October 1, 2015. The actual final rule date remains unknown at this time. More stringent standards may trigger additional control technology for mining equipment, or result in additional challenges to permitting and expansion efforts. Many of these air emissions 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 have been 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 U.S. Court of Appeals for the District of Columbia (D.C. Circuit) 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 U.S. Supreme Court (Supreme Court) were filed, and on October 15, 2013, the Supreme Court accepted six petitions for review, but only a single question is being considered: "Whether the EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases." A decision in the case will likely come by June 2014. This review will not affect the D.C. Circuit decision upholding the EPA's 2009 "endangerment finding" with respect to greenhouse gas emissions from new motor vehicles. However, the decision could have a significant impact on EPA rules, proposed rules and rules under development that may affect the demand for coal, including the proposed NSPS for carbon dioxide emissions from new fossil fuel-fired electric utility generating units and the performance standards under development for carbon dioxide emissions from existing power plants.

Proposed NSPS for Fossil Fuel-Fired Electricity Utility Generating Units. On April 13, 2012, the EPA published for comment proposed NSPS for emissions of carbon dioxide from new fossil fuel-fired electric utility generating units. If those 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. as CCS technologies are not yet commercially viable.

In light of over 2 million comments on its April 13, 2012 proposal and ongoing developments in the industry, the EPA subsequently indicated its intention to issue a new proposal. On June 25, 2013, the U.S. President directed the EPA to issue that new proposal by September 30, 2013 and to finalize it in a timely manner. On September 20, 2013, the EPA revoked its April 13, 2012 proposal and issued a new proposed NSPS for emissions of carbon dioxide from new fossil fuel-fired electric utility generating units, using section 111(b) of the Clean Air Act. On January 8, 2014, the re-proposal was published in the Federal Register, with the comment deadline stated as March 10, 2014.

The EPA has not yet proposed rules for modified sources under section 111(b) of the Clean Air Act or existing sources under section 111(d) of the Clean Air Act. However, the U.S. President directed the EPA, in the June 25, 2013 statement referred to above, to issue such standards, regulations or guidelines, as appropriate, addressing carbon pollution from existing, modified and reconstructed power plants. The President also requested that the EPA: (a) issue a proposal addressing such matters by June 1, 2014; (b) finalize it by June 1, 2015; and (c) include, in the guidelines addressing existing power plants, a requirement that states submit to the EPA implementation plans required under Section 111(d) of the Clean Air Act by June 30, 2016. We believe that any final rules issued by the EPA in this area will be challenged.

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. Under the CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions was 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 the CSAPR had an initial compliance deadline of January 1, 2012, the rule was challenged and on December 30, 2011, the D.C. Circuit 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 D.C. Circuit, which denied the EPA's petition on January 24, 2013. On March 29, 2013, the Solicitor General's Office, on behalf of the EPA, and, separately, certain non-governmental organizations, filed petitions for writs of certiorari with the Supreme Court seeking Supreme Court review of the D.C. Circuit's decision. The Supreme Court granted these petitions on June 24, 2013, held oral arguments on December 10, 2013 and will likely issue a decision by June 2014.

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Mercury and Air Toxic Standards (MATS). On December 16, 2011, the EPA issued 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 particulate matter for new and modified coal-fueled electricity generating plants. The MACT rule provides three years for compliance and a possible fourth year as a state permitting agency may deem necessary. On March 28, 2013, the EPA issued reconsidered MACT standards for new plants that are less stringent in some aspects than the standards issued in December 2011. On June 24, 2013, certain environmental organizations and industry groups filed an appeal of these regulations in the D.C. Circuit, and oral arguments were held on December 10, 2013. The rule could result in the retirement of certain older coal plants.

Clean Water Act. The Clean Water Act of 1972 directly impacts 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.

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.

In September 2013, a draft rule identifying waters protected by the Clean Water Act was sent to the Office of Management and Budget. This draft rule may be formally proposed by the EPA in early 2014, but we believe the final rule will not likely be issued until 2015. Litigation is likely from various stakeholders. If CWA authority is eventually expanded, it may impact our operations in some areas by way of additional requirements.

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 can involve 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. A recent federal district court decision in the District of Columbia requires the EPA to soon submit to the court a proposed deadline for completing the agency’s CCR rulemaking process. This EPA initiative is separate from the OSM CCR rulemaking mentioned above.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Although typically not applied to the coal mining sector, CERCLA, which was enacted in 1980, nonetheless may affect U.S. coal mining 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. 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, the EPA's Toxic Release Inventory program requires companies to report the use, manufacture or processing of listed toxic materials that exceed established 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 our costs or our ability to mine some of our properties in accordance with our current mining plans.

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Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. 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 expected to finalize an ammonium nitrate security program rule in 2014. While such new regulations may result in additional costs related to our surface mining operations, such costs are not expected to have a material adverse effect on our results of operations, financial condition or cash flows.

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, a water resource, 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 surrounding the protection of agriculture, water resources and critical industry clusters are under consideration.

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Occupational Health and Safety. State legislation requires us to provide and maintain a safe working environment for the people employed in our mines including by providing safe systems of work, safety equipment and appropriate information, instruction, training and supervision. In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under state legislation specific to the coal mining industry. There are some differences in the application and detail of the laws, and mining operators, directors, officers and certain other employees are all subject to the obligations under this legislation.

Industrial Relations. A national industrial relations system administered by the federal government applies to all private sector employers and employees. The matters regulated under the national system include employment conditions, unfair dismissal, enterprise bargaining, industrial action and resolution of workplace disputes. Many of the workers employed in our mines are covered by enterprise agreements approved under the national system.

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 Regulator administers the NGER Act. The Department of Environment 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 ultimate impact of these royalty rates will depend upon the volume of tonnes produced at each of our Queensland mining locations and coal prices received for those tonnes.

2013 Australian Elections. A federal election to determine the members of the 44th Parliament of Australia was held on September 7, 2013, resulting in the overall defeat of the incumbent Australian Labor Party by the Liberal-National Party coalition (the Coalition). Prior to the election, the Coalition called for the repeal of the Australian government’s carbon pricing framework and Minerals Resource Rent Tax (MRRT), both of which are discussed in additional detail below, and reiterated that stance when it released its Resource and Energy Policy. On November 20, 2013, Australia's House of Representatives voted to repeal the carbon pricing framework and the MRRT, thereby sending the related legislative packages to the Senate for consideration in 2014. While we would anticipate a modest improvement in our costs from the repeal of this legislation, the timing and likelihood of success of such a repeal remains uncertain.

Carbon Pricing Framework. The Australian government's carbon pricing framework commenced on July 1, 2012, with an initial carbon price of $23.00 Australian dollars per tonne of carbon dioxide equivalent emissions, scheduled to escalate by 2.5% per year for inflation over a three year period and transition to an emissions trading scheme after June 30, 2015. All of our Australian operations have been 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). Net of transition benefits, we recognized expense of approximately $40 million and $15 million in 2013 and 2012, respectively, related to this framework.

MRRT. On March 29, 2012, Australia passed legislation creating 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, 2013, we had recorded a net deferred tax asset of approximately $15 million related to the MRRT.

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Regulatory Matters — Financial Markets and Derivatives

Dodd-Frank Act - Derivatives Regulation. On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) was enacted, which among other things, requires the Commodity Futures Trading Commission (CFTC) and the SEC to adopt new comprehensive regulations related to financial derivative transactions. The CFTC and SEC have finalized many definitions and rule makings and the full impact of the new regulatory regime has mostly taken shape. We are eligible for the commercial end-user exemption available under the Dodd-Frank Act and are in full compliance with the finalized portion of these regulations. We expect that the Dodd-Frank Act will primarily continue to impact us through an increase in compliance and transaction costs associated with our corporate hedging and trading and brokerage activities.

European Markets Infrastructure Regulation (EMIR). In July 2012, the European Commission adopted EMIR, which is related to over-the-counter derivatives, central counterparties and trade repositories. EMIR requires that information on all European derivative transactions be reported to trade repositories and accessible to supervisory authorities, including the European Securities and Markets Authority. The regulation also requires standard derivative contracts to be cleared through Central Counterparties (CCPs), requires margining for uncleared trades and establishes stringent organizational, business conduct and prudential requirements for these CCPs. In December 2012, the European Commission adopted technical standards complimenting the regulation. We expect that EMIR and the related technical standards will increase compliance and transaction costs associated with our corporate hedging and trading and brokerage activities. The legislation is not expected to have an impact on our trading strategies utilized to hedge or mitigate risk related to asset production and commercial activities.

Markets in Financial Instruments Directive (MiFID). In October 2011, the European Commission adopted proposals to revise its MiFID and to enact a new Markets in Financial Instruments Regulation. We expect these will increase compliance and transaction costs associated with our corporate hedging and trading and brokerage activities.

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, 10 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.

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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 in our Corporate and Social Responsibility Report 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.

In 2013, the U.S. and a number of international development banks, including the World Bank, the European Investment Bank and the European Bank for Reconstruction and Development, announced that they would no longer provide financing for the development of new coal-fueled power plants or would do so only in narrowly defined circumstances. Other international development banks, such as the Asian Development Bank, have indicated that they will continue to provide such financing.

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. On November 20, 2013, Australia's House of Representatives voted to repeal the carbon pricing framework, thereby sending the related legislative package to the Senate for consideration in 2014.

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

Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., some of its states or other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future. The potential financial impact on us of future laws, regulations or other policies 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, regulations or other policies, the time periods over which those laws, regulations or other policies 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, regulations or other policies 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) 342-7900 or by mail at: Peabody Energy Corporation, Peabody Plaza, 701 Market Street, St. Louis, Missouri 63101-1826, attention: Investor Relations.

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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;
- changes in the fuel consumption patterns of electric power generators;
- 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 and natural gas industry output and 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 leases; 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 typical practice, is to negotiate pricing for metallurgical coal contracts quarterly and seaborne thermal coal contracts annually, with a portion sold on a shorter-term basis.

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.

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 increase the price of coal beyond specified limits.

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

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

For the year ended December 31, 2013, we derived 25% of our total revenues from our five largest customers. Those five customers were supplied primarily from 46 coal supply agreements (excluding trading transactions) expiring at various times from 2014 to 2026. The contract contributing the greatest amount of annual revenue in 2013 was approximately $340 million, or approximately 5% of our 2013 total revenue base. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and those customers may not continue to purchase coal from us under long-term coal supply agreements. If a number of these customers significantly reduce their purchases of coal from us, or if we are unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially. In addition, our revenue could be adversely affected by a decline in customer purchases due to lack of demand, cost of competing fuels and environmental and other governmental 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 or below levels experienced in 2013 for a prolonged period 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.

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 are 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 mine water discharges; weather, flooding and natural disasters; unexpected maintenance problems; unforeseen delays in implementation of mining technologies that are new to our operations; key equipment failures; variations in coal seam thickness; variations in coal quality; 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, such conditions 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 use 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, 2013, certain of our coal supply agreements permit the customer to terminate the contract if the cost of transportation increases by an amount over specified levels in any given 12-month period.

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We depend upon rail, barge, trucking, overland conveyor and ocean-going vessels to deliver coal to our customers. 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 in the U.S. and both surface and underground equipment globally, 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 the prices we receive for our coal products.

We have substantial take-or-pay arrangements, predominately in Australia, totaling $3.7 billion, with terms ranging up to 26 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.

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. While we completed several conversions to owner-operator status at certain of our Australian operations in 2013, a portion of our sales volume continues to come from mines that utilize contract miners. Employee relations at mines that use contract miners are the responsibility of the contractor.

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

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

We enter into hedging arrangements designed primarily to manage market price volatility of foreign currency (primarily the Australian dollar), diesel fuel, coal 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 changes of foreign currency, diesel fuel, coal and explosives.

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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 portfolio moves 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.

We may not recover our investments in our mining, exploration and other assets, which may require us to recognize impairment charges related to those assets.

The value of our assets may be adversely affected by numerous uncertain factors, some of which are beyond our control, including unfavorable changes in the economic environments in which we operate, lower-than-expected coal pricing, technical and geological operating difficulties, an inability to economically extract our coal reserves and unanticipated increases in operating costs. These may cause us to fail to recover all or a portion of our investments in those assets and may trigger the recognition of impairment charges in the future, which could have a substantial impact on our results of operations.

As described in Note 2. "Asset Impairment and Mine Closure Costs" to the accompanying consolidated financial statements, we recognized aggregate asset impairment and mine closure costs of $528.3 million and $929.0 million in 2013 and 2012, respectively. Because of the volatile nature of U.S. and international coal markets, it is reasonably possible that our current estimates of projected future cash flows from our mining assets may change in the near term, which may result in the need for further adjustments to the carrying value of those assets or adjustments to assets not previously impaired.

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, absent the completion of an orderly transition. In addition, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled and qualified personnel, particularly personnel with mining experience. We cannot provide assurance that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

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

As of December 31, 2013, we had approximately 8,300 employees, which included approximately 5,900 hourly employees. Approximately 35% of our hourly employees were represented by organized labor unions and generated 19% of 2013 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.

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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, 2013, we had $1,365.1 million of self bonding in place for our reclamation obligations. As of December 31, 2013, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of $1,086.6 million, of which $586.0 million was for post-mining reclamation, $135.0 million related to workers' compensation obligations, $109.9 million was for coal lease obligations and $255.7 million was for other obligations, including 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, which may in turn affect our available liquidity. Our ability to maintain and acquire letters of credit is subject to us maintaining compliance under our two primary facilities used for such items, which is our 2013 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 or our 2013 Credit Facility;
- the exercise by third-party surety bond issuers of their right to refuse to renew the surety; and
- the inability to renew our 2013 Credit Facility or a default thereunder.

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 and our liquidity available for other uses would be reduced.

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.

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. 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 limit 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. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include geological conditions, historical production from the area compared with production from other producing areas, the assumed effects of regulations and taxes by governmental agencies and assumptions governing future prices and future operating costs. Actual production, revenues and expenditures with respect to our coal reserves may vary materially from estimates.

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 and infrastructure. 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, 2013, we leased a total of 72,580 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 or appropriate land access 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.

Our global operations increase our risks unique to international mining and trading operations.

Our international platform increases our exposure to country risks and the effects of changes in currency exchange rates. Some of our international activities are in 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 exposed to 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.

Joint ventures, partnerships or non-managed operations may not be successful and may not comply with our operating standards.

We participate in several joint venture and partnership arrangements, and may enter into others, all of which necessarily involve risk. Whether or not we hold majority interests or maintain operational control in our joint ventures, our partners may, among other things, have economic or business interests or goals that are inconsistent with, or opposed to, ours; seek to block actions that the we believe are in our or the joint venture's best interests or be unable or unwilling to fulfill their obligations under the joint venture or other agreements, such as contributing capital. Where these joint ventures are jointly controlled or managed, we may provide expertise and advice but have limited control over compliance with our operational standards. Failure to adhere to equivalent standards at these operations could unfavorably affect operating costs and productivity and adversely impact our results of operations and reputation.

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 2013 Credit Facility.

As of December 31, 2013, we had $1.65 billion of maximum borrowing capacity under the 2013 Revolver portion of our 2013 Credit Facility and $1.5 billion of available capacity under that facility, net of outstanding letters of credit. This committed facility, which matures on September 24, 2018 (or on August 15, 2018 if our 6.00% Senior Notes due 2018 are still in existence on such date), 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 2013 Credit Facility syndicate consists of over 25 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, 2013, our total indebtedness was $6.0 billion, and we had $1.5 billion of maximum borrowing capacity under the 2013 Revolver portion of our 2013 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, the loss of trading counterparties for corporate hedging and trading and brokerage activities or an increase in the cost of, or a limit our access to, various forms of credit used in operating our business.

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 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 2013 Credit Facility, and the indentures governing our Senior Notes and Debentures impose restrictions that may limit our operating and financial flexibility.

Our 2013 Credit 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 2013 Credit Facility, we must comply with certain financial covenants on a quarterly basis including a maximum net secured leverage ratio and minimum interest coverage 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 in our 2013 Credit 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 2013 Credit Facility is conditioned upon compliance with these covenants, our actual borrowing capacity under the 2013 Credit Facility at any time may be less than the maximum borrowing capacity.

Adverse factors could result in our inability to comply with the financial covenants contained in our 2013 Credit Facility. If we violate these covenants and are unable to obtain waivers from our lenders, our 2013 Credit 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.

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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 and which does not necessarily involve an event of default). 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 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 and, if applicable, shares of our Common Stock.

Other Business Risks

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

Patriot Coal Company (Patriot) has approximately $150 million in federal and state black lung occupational disease liabilities related to workers employed in periods prior to Patriot’s spin-off from us in 2007. At the time of the spin-off, Patriot indemnified us against any claim relating to these liabilities, including any claim made by the U.S. Department of Labor (“DOL”) against us with respect to these obligations as a potentially liable operator under the Federal Coal Mine Health and Safety Act of 1969.

In 2012, Patriot and certain of its wholly owned subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code. In 2013, we entered into a definitive settlement agreement with Patriot and the United Mine Workers of America (UMWA), on behalf of itself, its represented Patriot employees and its represented Patriot retirees, to resolve all disputed issues related to Patriot’s bankruptcy. That agreement, which included Patriot’s affirmance of the indemnity relating to such black lung liabilities, became effective upon Patriot's emergence from bankruptcy on December 18, 2013.

If Patriot does not pay the black lung liabilities in the future, the DOL would first look to Patriot and any related credit support for payment before asserting any claims against the Company. While Patriot has agreed to indemnify us against any such claims by the DOL, we could be responsible for those liabilities if Patriot were not able to fund such indemnification.

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 $735.4 million as of December 31, 2013, $51.4 million of which was a current liability. Net pension liabilities were $95.9 million as of December 31, 2013, $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 unfavorable lending policies by government-backed lending institutions and development banks toward the financing of new overseas coal-fueled power plants, and interest in further such regulation and policies, 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., some of its states or other countries, or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future. The potential financial impact on us of future laws, regulations or other policies 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, regulations or other policies, the time periods over which those laws, regulations or other policies 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, regulations or other policies 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. Refer to Note 1 to the accompanying consolidated financial statements for a summary of our significant accounting policies.

Item 1B. Unresolved Staff Comments.

None.

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Item 2. Properties.

Coal Reserves

We had an estimated 8.3 billion tons of proven and probable coal reserves as of December 31, 2013. An estimated 7.3 billion tons of our attributable proven and probable coal reserves are in the U.S, with the remainder in Australia. Approximately 76% of our Australian proven and probable coal reserves, or 700 million tons, are metallurgical coal with the remainder being thermal coal. Approximately 53% of our reserves, or 4.3 billion tons, are compliance coal and 47% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). We own approximately 33% of these reserves and lease property containing the remaining 67%. 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, 2013 [1]		
Operating Regions	Locations	Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	2,401	798	3,199
Powder River Basin	Wyoming	—	3,386	3,386
Southwest	Arizona and New Mexico	303	245	548
Colorado	Colorado	28	179	207
Total United States		2,732	4,608	7,340
New South Wales	Australia	—	304	304
Queensland	Australia	—	621	621
Total Australia		—	925	925
Total Proven and Probable Coal Reserves		2,732	5,533	8,265

(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.

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.

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The preparation of our coal reserve estimates is 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. Our corporate Geological Services group is responsible for tracking changes in reserve estimates, supervising our other geologists and coordinating periodic third-party reviews of our reserve estimates by qualified mining consultants.

Our coal reserve estimates are predicated on information obtained from an extensive historical database of nearly 500,000 individual drill holes and information obtained from our ongoing drilling program. 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 generally 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. Factors impacting our assessment include geological conditions, production expectations for certain areas, the effects of regulation and taxes by governmental agencies, future price and operating cost assumptions and adverse changes in certain coal market segment conditions and mine closure activities. The estimates are also impacted by decreases resulting from current year production and increases resulting from information obtained from additional drilling. Our estimation as of December 31, 2013 reflected a reduction of 866 million tons of coal reserves, comprised of 578 million tons and 288 million tons in the U.S. and Australia, respectively, that were included in our prior year estimates but are no longer considered reserves under SEC Industry Guide 7. The reduction in the U.S. relates to reserves that were under consideration for a coal-to-gas project that have been removed from our estimate based on additional review performed by us in the current year. The reserves in Australia relate to reserves in the Surat Basin that are no longer considered economical due to mine closure activities.

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 U.S. Bureau of Land Management (BLM) 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, 2013, we leased 11,768 acres of federal land in Colorado, 640 acres in New Mexico and 51,910 acres in Wyoming, for a total of 64,318 nationwide subject to those limitations. An additional 8,262 acres in Wyoming are held under U.S. federal coal reserves we lease from the BLM, which are also subject to the U.S. federal government limits.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 64,785 acres of land in northern Arizona lying within the boundaries of the Navajo Nation and Hopi Indian reservations. We also lease coal-mining properties from various state governments in the U.S.

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

Mining and exploration in Australia is generally carried out 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 8.3 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, 2013, 2012 and 2011, 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, 2013 (1)			
	Year	Year	Year		<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	As
	Ended	Ended	Ended		Sulfur	Sulfur	Sulfur	Received
Geographic Region /	Dec. 31,	Dec. 31,	Dec. 31,	Type of	Dioxide per	Dioxide per	Dioxide per	Btu per
Mining Complex	2013	2012	2011	Coal	Million Btu	Million Btu	Million Btu	pound (2)
Midwest:								
Bear Run	8.2	7.9	6.5	T	5	28	241	11,500
Francisco Underground	2.9	2.8	3.0	T	—	—	46	11,500
Gateway	2.8	2.8	3.3	T	—	—	3	11,000
Somerville Central	2.6	2.3	3.0	T	—	—	3	11,500
Wild Boar	2.1	2.0	1.8	T	—	—	11	11,000
Cottage Grove	2.0	2.0	1.9	T	—	—	19	12,700
Wildcat Hills Underground	1.6	1.5	1.0	T	—	—	28	12,100
Somerville South	1.5	1.4	1.2	T	—	—	6	11,100
Somerville North	1.5	1.2	1.4	T	—	—	3	11,200
Viking - Corning Pit (3)	1.1	1.3	1.5	T	—	—	—	11,500
Willow Lake (Closed in 2012)	—	2.1	2.2	T	—	—	—	NA
Total	26.3	27.3	26.8		5	28	360	
Powder River Basin:								
North Antelope Rochelle	111.0	107.6	109.1	T	2,254	—	—	8,800
Rawhide	14.2	14.7	15.0	T	238	56	2	8,300
Caballo	9.0	16.9	24.1	T	722	100	14	8,300
Total	134.2	139.2	148.2		3,214	156	16	
Southwest:								
El Segundo	8.7	8.6	8.1	T	27	63	68	9,100
Kayenta	7.2	7.5	8.1	T	153	68	3	10,600
Lee Ranch	—	1.3	2.0	T	20	61	57	9,300
Total	15.9	17.4	18.2		200	192	128	
Colorado:								
Twentymile	7.2	8.0	7.7	T	14	—	38	11,200
Australia:								
Wilpinjong	13.3	12.2	10.9	T	—	162	—	11,200
Wambo (4)	6.9	6.6	5.8	T/P	109	—	—	12,200
Millennium	3.5	3.2	1.9	M/P	27	—	—	12,600
Coppabella	3.2	2.8	0.4	P	74	—	—	12,700
North Goonyella / Eaglefield	2.3	4.1	2.2	M	98	—	—	12,900

Moorvale	2.1	1.9	0.3	M/P	19	—	—	12,100
Burton	2.0	1.2	2.1	T/M	12	—	—	12,700
Metropolitan	1.5	1.8	1.8	M	33	—	—	12,600
Middlemount (5)	—	—	—	M/P	34	—	—	12,300
Total	34.8	33.8	25.4		406	162	—	
Total Continuing Operations	218.4	225.7	226.3		3,839	538	542	
Discontinued Operations	4.0	3.3	2.6		—	—	—	
Total Assigned	222.4	229.0	228.9		3,839	538	542	

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection

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ASSIGNED RESERVES [6]
AS OF DECEMBER 31, 2013

(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%	274	121	153	274	—	274	121	153	274	—
Francisco Underground	100%	46	9	37	—	46	46	9	37	—	46
Wildcat Hills Underground	100%	28	15	13	—	28	28	15	13	—	28
Cottage Grove	100%	19	10	9	19	—	19	10	9	19	—
Wild Boar	100%	11	8	3	11	—	11	8	3	11	—
Somerville South	100%	6	5	1	6	—	6	5	1	6	—
Gateway	100%	3	2	1	—	3	3	2	1	—	3
Somerville Central	100%	3	2	1	3	—	3	2	1	3	—
Somerville North	100%	3	1	2	3	—	3	1	2	3	—
Viking - Corning Pit	100%	—	—	—	—	—	—	—	—	—	—
Total		393	173	220	316	77					
Powder River Basin:											
North Antelope Rochelle	100%	2,254	—	2,254	2,254	—	2,254	—	2,254	2,254	—
Caballo	100%	836	—	836	836	—	836	—	836	836	—
Rawhide	100%	296	—	296	296	—	296	—	296	296	—
Total		3,386	—	3,386	3,386	—					
Southwest:											
Kayenta	100%	224	—	224	224	—	224	—	224	224	—
El Segundo	100%	158	145	13	158	—	158	145	13	158	—
Lee Ranch	100%	138	130	8	138	—	138	130	8	138	—
Total		520	275	245	520	—					
Colorado:											
Twentymile	100%	52	13	39	—	52	52	13	39	—	52
Australia:											
Wilpinjong	100%	162	—	162	162	—	162	—	162	162	—
Wambo [4]	100%	109	—	109	47	62	109	—	109	47	62
North Goonyella / Eaglefield	100%	98	—	98	1	97	98	—	98	1	97

Coppabella	73.3%	74	—	74	67	7	101	—	101	91	10
Metropolitan	100%	33	—	33	—	33	33	—	33	—	33
Millennium	100%	27	—	27	27	—	27	—	27	27	—
Moorvale	73.3%	19	—	19	19	—	26	—	26	26	—
Burton	100%	12	—	12	12	—	12	—	12	12	—
Middlemount (5)	50.0%	34	—	34	34	—	68	—	68	68	—
Total		568	—	568	369	199					
Total Assigned		4,919	461	4,458	4,591	328					

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES
AS OF DECEMBER 31, 2013
(Tons in Millions)

	Attributable Ownership					100% Project Basis				
	Total Tons		Proven and Probable			Total Tons		Proven and Probable		
Coal Seam Location	Assigned	Unassigned	Reserves	Proven	Probable	Assigned	Unassigned	Reserves	Proven	Probable
Midwest:										
Illinois	50	2,157	2,207	1,043	1,164	50	2,157	2,207	1,043	1,164
Indiana	343	309	652	496	156	343	309	652	496	156
Kentucky	—	340	340	151	189	—	340	340	151	189
Total	393	2,806	3,199	1,690	1,509					
Powder River Basin (Wyoming)	3,386	—	3,386	3,221	165	3,386	—	3,386	3,221	165
Southwest:										
Arizona	224	—	224	224	—	224	—	224	224	—
New Mexico	296	28	324	302	22	296	28	324	302	22
Total	520	28	548	526	22					
Colorado	52	155	207	126	81	52	155	207	126	81
Australia:										
New South Wales	304	—	304	207	97	304	—	304	207	97
Queensland [7]	264	357	621	450	171	332	535	867	605	262
Total	568	357	925	657	268					
Total Proven and Probable	4,919	3,346	8,265	6,220	2,045					

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ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2013
(Tons in Millions)

	Attributable Ownership				100% Project Basis			
	Reserve Control		Mining Method		Reserve Control		Mining Method	
Coal Seam Location	Owned	Leased	Surface	Underground	Owned	Leased	Surface	Underground
Midwest:								
Illinois	1,867	340	62	2,145	1,867	340	62	2,145
Indiana	346	306	454	198	346	306	454	198
Kentucky	188	152	32	308	188	152	32	308
Total	2,401	798	548	2,651				
Powder River Basin (Wyoming)	—	3,386	3,386	—	—	3,386	3,386	—
Southwest:								
Arizona	—	224	224	—	—	224	224	—
New Mexico	303	21	324	—	303	21	324	—
Total	303	245	548	—				
Colorado	28	179	—	207	28	179	—	207
Australia:								
New South Wales	—	304	209	95	—	304	209	95
Queensland [7]	—	621	517	104	—	867	704	163
Total	—	925	726	199				
Total Proven and Probable	2,732	5,533	5,208	3,057				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2013
(Tons in Millions)

Coal Seam Location	Type of Coal	Attributable Ownership Sulfur Content [1] <1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	100% Project Basis Sulfur Content [1] <1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	As Received Btu per Pound [2]
Midwest:								
Illinois	T	—	—	2,207	—	—	2,207	10,300
Indiana	T	5	36	611	5	36	611	10,200
Kentucky	T	—	—	340	—	—	340	10,900
Total		5	36	3,158				
Powder River Basin (Wyoming)	T	3,214	156	16	3,214	156	16	8,700
Southwest:								
Arizona	T	154	68	2	154	68	2	11,000
New Mexico	T	48	145	131	48	145	131	9,400
Total		202	213	133				
Colorado	T	157	—	50	157	—	50	10,700
Australia:								
New South Wales	T/M/P	142	162	—	142	162	—	11,800
Queensland [7]	T/M/P	621	—	—	867	—	—	12,100
Total		763	162	—				
Total Proven and Probable		4,341	567	3,357				

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection

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

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

(3) The Viking - Corning Pit mine is scheduled to close in the first half of 2014 due to the exhaustion of coal reserves.

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

(5) Middlemount represents our 50.0% interest in Middlemount Coal Pty Ltd., which owns the Middlemount Mine in Queensland, Australia. Because that entity is accounted for as an unconsolidated equity affiliate, 2013 tons produced have been excluded from the "Summary of Coal Production and Sulfur Content of Assigned Reserves" table.

(6) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2013. Unassigned reserves represent coal at currently non-producing locations that would require new mine development, mining equipment or plant facilities before operations could begin on the property.

(7) Unassigned reserves in Queensland include approximately 56 million tons of reserves for a non-strategic exploration tenement asset that was sold in January 2014.

Item 3. Legal Proceedings.

See Note 24. "Commitments and Contingencies" to our consolidated financial statements for a description of our pending legal proceedings, which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures.

Safety is a core value that is integrated into all areas of our business. Our goal is to provide a workplace that is incident free. We believe that it is our responsibility to provide a safe and healthy work environment. We seek to implement this goal by: training employees in safe work practices; openly communicating with employees; establishing, following and improving safety standards; involving employees in safety processes and recording, reporting and investigating accidents, incidents and losses to avoid recurrence. As part of our training, we collaborate with the Mine Safety and Health Administration (MSHA) and other government agencies to identify and test emerging safety technologies. We also believe personal accountability is key; every employee commits to our safety goals and governing principles. All employees are held accountable for their own safety and the safety of other employees.

We also partner with other companies and certain governmental agencies to pursue new technologies that have the potential to improve our safety performance and provide better safety protection for employees. We are currently partnering with three of our mining equipment vendors to incorporate proximity detection systems on our continuous miners and proximity detection and video surveillance systems on our battery-powered coal haulage equipment, shuttle cars and section scoops at our U.S. underground mines. Additionally, we have installed and are testing a proximity detection system for large mining equipment and light vehicles at one of our Australian surface mines. We have also initiated a collaborative effort with certain vendors to identify and evaluate potential fatigue monitoring programs and technologies for our surface operations.

In 2012, we announced our endorsement and participation in CORESafety™, a new safety and health management system developed by member companies of the National Mining Association for the U.S. mining industry. CORESafety™ is an approach to safety and health focused on preventing accidents through the use of a management system that focuses on leadership development, management processes, individual accountability and assurance techniques. As a continuation of the integration of the elements of CORESafety™ into our "Safety, A Way of Life Management System," we conducted a safety risk management workshop with the senior management team of our U.S. operations facilitated by a global expert on safety risk management in mining. We are putting these concepts into action by developing and implementing Safety Risk Registers for all of our U.S. mining operations. Such actions were completed at five of our U.S. mines in 2013 and will be completed at our remaining U.S. locations in 2014.

We primarily measure our safety performance based on our incidence rate, which is monitored through our safety tracking system and represents the number of injuries that occurred for each 200,000 employee hours worked. Accordingly, it is computed as the number of injury occurrences (MSHA reportable injury degree codes 1 through 6) divided by the number of employee hours worked and multiplied by 200,000 [(number of injury occurrences ÷ number of employee hours worked) x 200,000]. Since MSHA is a branch of the U.S. Department of Labor, its jurisdiction applies only to our U.S. mines. While not required by U.S. law, we also track incidence rates for our Australian mines using the same criteria.

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

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

	Year Ended December 31,		
	2013	2012	2011
MSHA (U.S. coal mines)(1)	3.42	3.56	3.76
U.S.(2)	1.00	1.28	1.50
Australia(2)	2.79	2.50	2.77
Total Peabody Energy Corporation(2)	1.87	1.87	2.00

(1) The 2013 MSHA all incidence rate for operators at all U.S. bituminous coal mines, excluding the impact of office workers, reflected above represents preliminary results for January through September 2013 based on the data most recently published by MSHA as of February 20, 2014.

(2) Results for the year ended December 31, 2011 exclude PEA-PCI, previously Macarthur Coal Limited. Results for all periods include certain mines classified as discontinued operations and inactive operations in the process of being reclaimed during the periods presented. Excluding those impacts, our incidence rates for the U.S., Australia and worldwide were 0.97, 2.69 and 1.80, respectively, in 2013 and 1.20, 2.50 and 1.83, respectively, in 2012.

We monitor MSHA compliance using violations per inspection day (in the U.S. only), which is calculated as the total count of violations per five hour MSHA inspector day. Similar to historical incidence rates, historical violations per inspection day may be adjusted over time to reflect the final resolution of the underlying matters. For the years ended December 31, 2013, 2012 and 2011, our U.S. violations per inspection day were 0.57, 0.79 and 0.80, respectively.

On July 2, 2013, an employee at our Wildcat Hills underground mine in Illinois was fatally injured as the result of a coal haulage incident. The mine was immediately idled for investigation. The mine resumed production with MSHA's concurrence with three out of five continuous miners on July 9, 2013, and an additional continuous miner resumed production on July 11, 2013. The mine was issued a citation and a 104(b) order by MSHA on July 24, 2013, was temporarily idled again and resumed full production on August 2, 2013 when practices were adopted to comply with a MSHA-imposed safety requirement. The 104(b) order was subsequently vacated pursuant to a settlement with MSHA approved on October 25, 2013.

The information concerning mine safety violations or other regulatory matters required by SEC regulations is included in Exhibit 95 to this Annual Report on Form 10-K.

PART II

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

Our common stock is listed on the New York Stock Exchange, under the symbol “BTU.” As of February 14, 2014, there were 1,387 holders of record of our common stock.

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

	Share Price		Dividends
	High	Low	Paid
2013			
First Quarter	$27.32	$20.44	$0.085
Second Quarter	21.17	14.54	0.085
Third Quarter	18.88	14.65	0.085
Fourth Quarter	20.87	16.93	0.085
2012			
First Quarter	$38.90	$28.83	$0.085
Second Quarter	31.59	21.12	0.085
Third Quarter	26.21	19.05	0.085
Fourth Quarter	29.28	21.81	0.085

Dividend Policy

We have declared and paid quarterly dividends since our initial public offering in 2001. On January 23, 2014, our Board of Directors declared a dividend of $0.085 per share of Common Stock, payable on February 27, 2014, to stockholders of record on February 6, 2014. The declaration and payment of dividends and the amount of dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors. Limitations on our ability to pay dividends imposed by our debt instruments are discussed in Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Share Repurchases

On October 24, 2008, we announced that our Board of Directors approved an amendment to the then existing share repurchase program to authorize repurchases of up to $1.0 billion of the then outstanding shares of our common stock (Repurchase Program). The Repurchase Program does not have an expiration date and may be discontinued at any time. Through December 31, 2013, we have repurchased a total of 7.7 million shares under the Repurchase Program at a cost of $299.6 million ($199.8 million and $99.8 million in 2008 and 2006, respectively), leaving $700.4 million available for share repurchases under the Repurchase Program. Repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. No share repurchases were made under the Repurchase Program during the years ended December 31, 2013, 2012 or 2011.

Our Chairman and Chief Executive Officer had authority to direct the repurchase up to $100.0 million of common stock outside of the Repurchase Program. During the second quarter of 2012, we utilized existing cash on hand to repurchase 4.2 million shares of outstanding common stock for $99.9 million pursuant to that authority through open-market transactions.

Share Relinquishments

We routinely allow employees to relinquish common stock to pay estimated taxes upon the vesting of restricted stock and the payout of performance units that are settled in common stock under our equity incentive plans. The value of common stock tendered by employees is determined based on the closing price of our common stock on the dates of the respective relinquishments.

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Purchases of Equity Securities

The following table summarizes all share purchases for the three months ended December 31, 2013:

Period	Total Number of Shares Purchased[1]	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Dollar Value that May Yet Be Used to Repurchase Shares Under the Publicly Announced Program (In millions)
October 1 through October 31, 2013	1,157	$17.25	—	$700.4
November 1 through November 30, 2013	—	—	—	700.4
December 1 through December 31, 2013	11,438	19.49	—	700.4
Total	12,595	$19.28	—	

[1] Represents shares withheld to cover the withholding taxes upon the vesting of restricted stock, which are not a part of the Repurchase Program.

Equity Compensation Plan Information

Refer to Part II, Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" for the information required by Item 201(d) of Regulation S-K regarding our equity compensation plans, which information is incorporated herein by reference.

Item 6. Selected Financial Data.

The following table presents selected financial and other data about us for the most recent five fiscal years.

The following table and the discussion of our results of operations in 2013, 2012 and 2011 in Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” includes references to and analysis of Adjusted EBITDA, Adjusted Income from Continuing Operations and Adjusted Diluted EPS, which are financial measures not recognized in accordance with U.S. generally accepted accounting principles (GAAP). These financial measures are not intended to serve as alternatives to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies. Beginning with this report, we have modified the definitions of these non-GAAP financial measures to also exclude the impact of charges for the settlement of claims and litigation related to previously divested operations because we believe that excluding these impacts is useful in comparing our 2013 results with those of prior and future periods.

Adjusted EBITDA is defined as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization, asset impairment and mine closure costs, charges for the settlement of claims and litigation related to previously divested operations and amortization of basis difference related to equity affiliates. Adjusted EBITDA is the primary metric used by management to measure our segments’ operating performance and we believe it is useful to external users of our financial statements in comparing our current results with those of prior and future periods and in evaluating our operating performance without regard to our capital structure or the cost basis of our assets.

Adjusted Income from Continuing Operations and Adjusted Diluted EPS are defined as (loss) income from continuing operations and diluted earnings per share from continuing operations (EPS), respectively, excluding the impacts of asset impairment and mine closure costs and charges for the settlement of claims and litigation related to previously divested operations, net of tax, and the remeasurement of foreign income tax accounts on our income tax provision. The income tax benefits related to asset impairment and mine closure costs and charges for the settlement of claims and litigation related to previously divested operations have been calculated based on the enacted tax rate in the jurisdiction in which they have been or will be realized, adjusted for the estimated recoverability of those benefits. We have included Adjusted Income from Continuing Operations and Adjusted Diluted EPS in our discussion because, in the opinion of management, excluding those foregoing items is useful in comparing our current results with those of prior and future periods. We also believe that excluding the impact of the remeasurement of our foreign income tax

accounts represents a meaningful indicator of our ongoing effective tax rate.
Reconciliations of Adjusted EBITDA, Adjusted Income from Continuing Operations and Adjusted Diluted EPS to their most comparable measures under U.S. GAAP are included below.
The selected financial data for all periods presented reflect the classification as discontinued operations of certain operations previously divested (by sale or otherwise).

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On October 26, 2011, we acquired Macarthur Coal Limited (PEA-PCI). Our results of operations include PEA-PCI's results of operations from that date.

We have derived the selected historical financial data as of and for the years ended December 31, 2013, 2012, 2011, 2010 and 2009 from our audited financial statements, adjusted retrospectively for items subsequently classified as discontinued operations and the implementation of certain accounting literature. The following table should be read in conjunction with the accompanying financial statements, including the related notes to those financial statements, and Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	$7,013.7	$8,077.5	$7,895.9	$6,668.2	$5,746.4
Costs and expenses	7,338.5	7,905.0	6,300.2	5,317.1	4,919.6
Operating (loss) profit	(324.8)	172.5	1,595.7	1,351.1	826.8
Interest expense, net	409.5	381.1	219.7	212.4	193.0
(Loss) income from continuing operations before income taxes	(734.3)	(208.6)	1,376.0	1,138.7	633.8
Income tax (benefit) provision	(448.3)	262.3	363.2	313.7	187.8
(Loss) income from continuing operations, net of income taxes	(286.0)	(470.9)	1,012.8	825.0	446.0
(Loss) income from discontinued operations, net of income taxes	(226.6)	(104.2)	(66.5)	(22.8)	17.0
Net (loss) income	(512.6)	(575.1)	946.3	802.2	463.0
Less: Net income (loss) attributable to noncontrolling interests	12.3	10.6	(11.4)	28.2	14.8
Net (loss) income attributable to common stockholders	$(524.9)	$(585.7)	$957.7	$774.0	$448.2
Basic EPS - (Loss) income from continuing operations	$(1.12)	$(1.80)	$3.78	$2.96	$1.61
Diluted EPS - (Loss) income from continuing operations	$(1.12)	$(1.80)	$3.77	$2.92	$1.60
Weighted average shares used in calculating basic EPS	267.1	268.0	269.1	267.0	265.5
Weighted average shares used in calculating diluted EPS	267.1	268.0	270.3	269.9	267.5
Dividends declared per share	$0.340	$0.340	$0.340	$0.295	$0.250
Other Data					
Tons sold	251.7	248.5	249.4	243.1	239.7
Net cash provided by (used in) continuing operations:					
Operating activities	$780.1	$1,599.8	$1,652.1	$1,104.5	$1,038.6
Investing activities	(514.2)	(1,070.1)	(3,737.2)	(692.7)	(404.2)
Financing activities	(321.5)	(663.3)	1,678.5	(77.1)	(104.6)
Adjusted EBITDA	1,047.2	1,836.5	2,122.6	1,826.5	1,291.2
Adjusted Income from Continuing Operations	104.5	238.7	1,011.9	872.9	543.0
Adjusted Diluted EPS	$0.34	$0.84	$3.77	$3.10	$1.96
Balance Sheet Data (at period end)					
Total assets	$14,133.4	$15,809.0	$16,733.0	$11,363.1	$9,955.3
Total long-term debt (including capital leases)	6,002.4	6,252.9	6,657.5	2,750.0	2,752.3
Total stockholders' equity	3,947.9	4,938.8	5,515.8	4,689.3	3,755.9

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Adjusted EBITDA is calculated as follows:

	Year Ended December 31,				
	2013	2012	2011	2010	2009
		(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$(286.0)	$(470.9)	$1,012.8	$825.0	$446.0
Depreciation, depletion and amortization	740.3	663.4	474.3	429.5	390.8
Asset retirement obligation expenses	66.5	67.0	52.6	45.9	38.9
Asset impairment and mine closure costs	528.3	929.0	—	—	34.7
Settlement charges related to the Patriot bankruptcy reorganization	30.6	—	—	—	—
Amortization of basis difference related to equity affiliates	6.3	4.6	—	—	—
Interest expense, net	409.5	381.1	219.7	212.4	193.0
Income tax (benefit) provision	(448.3)	262.3	363.2	313.7	187.8
Adjusted EBITDA	$1,047.2	$1,836.5	$2,122.6	$1,826.5	$1,291.2

Adjusted Income from Continuing Operations is calculated as follows:

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(Dollars in millions)				
(Loss) income from continuing operations, net of income taxes	$(286.0)	$(470.9)	$1,012.8	$825.0	$446.0
Asset impairment and mine closure costs	528.3	929.0	—	—	34.7
Settlement charges related to the Patriot bankruptcy reorganization	30.6	—	—	—	—
Income tax benefit related to asset impairment and mine closure costs	(112.8)	(227.3)	—	—	(12.1)
Income tax benefit related to the settlement charges related to the Patriot bankruptcy reorganization	(11.3)	—	—	—	—
Remeasurement (benefit) expense related to foreign income tax accounts	(44.3)	7.9	(0.9)	47.9	74.4
Adjusted Income from Continuing Operations	$104.5	$238.7	$1,011.9	$872.9	$543.0

Adjusted Diluted EPS is calculated as follows:

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Diluted EPS - (Loss) income from continuing operations	$(1.12)	$(1.80)	$3.77	$2.92	$1.60
Asset impairment and mine closure costs, net of income taxes	1.56	2.61	—	—	0.08
Settlement charges related to the Patriot bankruptcy reorganization, net of income taxes	0.07	—	—	—	—
Remeasurement (benefit) expense related to foreign income tax accounts	(0.17)	0.03	—	0.18	0.28
Adjusted Diluted EPS	$0.34	$0.84	$3.77	$3.10	$1.96

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

Overview

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

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In 2013, we produced and sold 218.4 million and 251.7 million tons of coal, respectively, from continuing operations. During that period, approximately 80% of our worldwide sales (by volume) were under long-term contracts. For the year ended December 31, 2013, 73% of our total sales (by volume) were to U.S. electricity generators, 26% were to customers outside the U.S. and 1% were to the U.S. industrial sector.

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

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

The business of our Australian Mining segment is the mining of various qualities of metallurgical coal, as well as thermal coal. Our Australian Mining segment operations are primarily export focused with customers spread across several countries, with a portion of our coal being sold within Australia. Revenues from individual countries generally vary year by year based on demand for electricity and steel, global economic conditions and several other factors, including those specific to each country. Industry commercial practice, and our typical practice, is to negotiate pricing for those metallurgical and seaborne thermal coal contracts on a quarterly and annual basis, respectively, with a portion sold on a shorter-term basis.

The principal business of our Trading and Brokerage segment is the marketing and brokering of coal for other producers, both as principal and agent, and the trading of coal and freight-related contracts. From time to time and where possible, our Trading and Brokerage segment may enter into financial derivative contract positions offsetting certain coal purchase and sale contracts included in our portfolio in an effort to reduce market price risk and secure a margin on forecasted transactions. The segment also provides transportation-related services in support of our coal trading strategy, including economic hedging, and conducts cash flow hedging activities in support of sales from our mining operations.

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

To maximize our coal assets and land holdings for long-term growth, we are evaluating Btu Conversion projects that would convert coal to natural gas (CTG) or transportation fuels (CTL) and contributing to the development of clean coal technologies, including carbon capture and storage (CCS).

As discussed more fully in Part I, Item 1A. “Risk Factors,” our results of operations in the near-term could be negatively impacted by weather conditions, cost of competing fuels, availability of transportation for coal shipments, labor relations, unforeseen geologic conditions or equipment problems at mining locations and adverse changes in economic conditions in the regions in which we sell coal. On a long-term basis, our results of operations could be impacted by our ability to secure or acquire high-quality coal reserves, find replacement buyers for coal under contracts with comparable terms to existing contracts, competition from other fuel sources or the passage of new or expanded regulations that could limit our ability to mine, increase our mining costs or limit our customers’ ability to utilize coal as fuel for electricity generation. In the past, we have achieved production levels that are relatively consistent with our projections. We may adjust our production levels in response to changes in market demand.

Results of Operations

Non-U.S. GAAP Financial Measures

The following discussion of our results of operations includes references to and analysis of Adjusted EBITDA, Adjusted Income from Continuing Operations and Adjusted Diluted EPS, which are financial measures not recognized in accordance with U.S. generally accepted accounting principles (GAAP). These financial measures are not intended to serve as alternatives to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies. Beginning with this report, we have modified the definitions of these non-GAAP financial measures to also exclude the impact of charges for the settlement of claims and litigation related to previously divested operations because we believe that excluding these impacts is useful in comparing our 2013 results with those of prior and future periods.

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Adjusted EBITDA is defined as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization, asset impairment and mine closure costs, charges for the settlement of claims and litigation related to previously divested operations and amortization of basis difference related to equity affiliates. Adjusted EBITDA is the primary metric used by management to measure our segments' operating performance and we believe it is useful to external users of our financial statements in comparing our current results with those of prior and future periods and in evaluating our operating performance without regard to our capital structure or the cost basis of our assets.

Adjusted Income from Continuing Operations and Adjusted Diluted EPS are defined as (loss) income from continuing operations and diluted earnings per share from continuing operations (EPS), respectively, excluding the impacts of asset impairment and mine closure costs and charges for the settlement of claims and litigation related to previously divested operations, net of tax, and the remeasurement of foreign income tax accounts on our income tax provision. The income tax benefits related to asset impairment and mine closure costs and charges for the settlement of claims and litigation related to previously divested operations have been calculated based on the enacted tax rate in the jurisdiction in which they have been or will be realized, adjusted for the estimated recoverability of those benefits. We have included Adjusted Income from Continuing Operations and Adjusted Diluted EPS in our discussion because, in the opinion of management, excluding those foregoing items is useful in comparing our current results with those of prior periods. We also believe that excluding the impact of the remeasurement of our foreign income tax accounts represents a meaningful indicator of our ongoing effective tax rate.

A reconciliation of Adjusted EBITDA to its most comparable measure under U.S. GAAP is included in Note 27. "Segment and Geographic Information" of the consolidated financial statements, which information is incorporated herein by reference. Adjusted Income from Continuing Operations and Adjusted Diluted EPS are reconciled to their most comparable measures under U.S. GAAP in the sections that follow.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Summary

During the year ended December 31, 2013, the global coal market segments in which we sell our products were confronted with excess international seaborne coal supply and high coal stockpile inventories at U.S. electric power generation customers, the effects of which have impacted our results for the period. Indicators of improvement since the beginning of 2013 have been mixed.

Trends in global demand for metallurgical coal were positive during the year ended December 31, 2013, corresponding with a 3.5% increase in worldwide steel production during that period compared to the prior year, according to data recently published by the World Steel Association (WSA), with an increase in Asian steel production during that period offsetting a decline in steel production for the rest of the world. Similarly, international seaborne thermal coal demand increased in the year ended December 31, 2013 compared to the prior year, led by imports into China, India, Japan and Germany. Nonetheless, growth in seaborne coal market supply outpaced the increase in demand in 2013, leading to continued constraints on international coal prices. Quarterly benchmark pricing for seaborne high quality hard coking coal (HQHCC), low volatile pulverized coal injection products (LV PCI) and thermal coal originating from Newcastle, Australia (NEWC) for 2013 and 2012 were as follows (on a per tonne basis):

Contract Commencement Month:	HQHCC 2013	HQHCC 2012	Increase (Decrease) to Prices %	LV PCI 2013	LV PCI 2012	Increase (Decrease) to Prices %	NEWC 2013	NEWC 2012	Increase (Decrease) to Prices %
January	$165	$235	(30)%	$124	$171	(27)%	$91	$115	(21)%
April	$172	$210	(18)%	$141	$153	(8)%	$95	$115	(17)%
July	$145	$225	(36)%	$116	$162	(28)%	$90	$95	(5)%
October	$152	$170	(11)%	$121	$125	(3)%	$86	$97	(11)%

U.S. coal consumption increased by 3.5% during the year ended December 31, 2013 compared to the prior year, led by the electric power generation sector, according to the U.S. Energy Information Administration (EIA). Current year U.S. electric power generation from coal has benefited from gas-to-coal switching due to higher natural gas prices and higher heating-degree days during the winter months of 2013, partially offset by lower cooling-degree days in 2013. Despite the year-over-year increase in U.S. coal consumption, our U.S. sales volumes declined in 2013 compared to

2012 as electric power generation customers continued to draw down on their coal stockpile inventories throughout the year to serve that increase in demand.

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Our revenues decreased during the year ended December 31, 2013 compared to the prior year ($1,063.8 million) due to lower average realized pricing across our global platform, lower volumes in the U.S. and lower Trading and Brokerage contributions, partially offset by an increase in Australian Mining segment tons sold from expansion projects completed in 2012.

In light of lower revenues, we focused on controlling costs at all levels of the organization throughout 2013. We completed owner-operator conversions at several of our Australian mines during the second quarter of 2013, realized productivity improvements at certain Australian operations acquired in late 2011 from optimization and remediation efforts completed in the prior year and reduced the use of contractors, temporary labor and overtime across the platform. These cost control initiatives partially offset the effect of lower coal prices. Overall, Segment Adjusted EBITDA decreased during the year ended December 31, 2013 compared to the prior year ($902.1 million).

Net results attributable to common stockholders improved during the year ended December 31, 2013 compared to the prior year ($60.8 million). The impact of lower Adjusted EBITDA, an increase in depreciation, depletion and amortization, higher interest expense and adverse changes in results from discontinued operations were more than offset by the positive effect of an overall income tax benefit recorded in 2013 and a decrease in asset impairment and mine closures costs, as discussed below.

As of December 31, 2013, our available liquidity was approximately $2.1 billion. Refer to the "Liquidity and Capital Resources" section contained within this Item 7 for further discussion of factors affecting our available liquidity.

Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Tons Sold	
	2013	2012	Tons	%
	(Tons in millions)			
Australian Mining	34.9	33.0	1.9	5.8 %
Western U.S. Mining	158.8	165.2	(6.4)	(3.9)%
Midwestern U.S. Mining	26.3	27.4	(1.1)	(4.0)%
Trading and Brokerage	31.7	22.9	8.8	38.4 %
Total tons sold	251.7	248.5	3.2	1.3 %

Revenues

The following table presents revenues by operating segment for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2013	2012	$	%
	(Dollars in millions)			
Australian Mining	$2,904.6	$3,503.6	$(599.0)	(17.1)%
Western U.S. Mining	2,669.6	2,949.3	(279.7)	(9.5)%
Midwestern U.S. Mining	1,335.5	1,403.7	(68.2)	(4.9)%
Trading and Brokerage	66.0	199.9	(133.9)	(67.0)%
Corporate and Other	38.0	21.0	17.0	81.0 %
Total revenues	$7,013.7	$8,077.5	$(1,063.8)	(13.2)%

The decrease in our Australian Mining segment revenues for the year ended December 31, 2013 compared to the prior year was primarily driven by the aforementioned decline in settlement prices for metallurgical and thermal coal ($742.7 million). That unfavorable pricing effect was partially offset by an increase in tons sold in 2013 ($143.7 million) attributed to improved production capacity and efficiency from certain growth and development projects completed in the second half of 2012. The increase in production was somewhat tempered in 2013 by geologic issues and delays in the commissioning of longwall top coal caving technology at our North Goonyella Mine and geologic issues and an industrial action at our Metropolitan Mine that was resolved in November 2013. Metallurgical coal sales totaled 15.9 million and 14.1 million tons in 2013 and 2012, respectively.

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Western U.S. Mining segment revenues were negatively affected by lower realized pricing in the year ended December 31, 2013 compared to the prior year ($145.7 million). The impact of year-over-year changes in volume and mix was also unfavorable in 2013 ($134.0 million), corresponding with the 3.9% decrease in tons sold noted above. Midwestern U.S. Mining segment revenues decreased slightly in 2013 compared to the prior year, predominantly from a 4.0% decrease in sales volumes.

The decline in our Trading and Brokerage segment revenues during the year ended December 31, 2013 compared to the prior year reflected lower realized prices on export shipments, a decrease in throughput and margins from certain third-party Eastern U.S. coal miners due to lower year-over-year coal production, unfavorable changes in the fair value of our global financial trading positions and supply performance issues related to certain international counterparties.

Segment Adjusted EBITDA

The following table presents Segment Adjusted EBITDA for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2013	2012	$	%
	(Dollars in millions)			
Australian Mining	$316.6	$938.9	$(622.3)	(66.3)%
Western U.S. Mining	693.2	832.8	(139.6)	(16.8)%
Midwestern U.S. Mining	426.4	427.0	(0.6)	(0.1)%
Trading and Brokerage	(19.9)	119.7	(139.6)	(116.6)%
Total Segment Adjusted EBITDA	$1,416.3	$2,318.4	$(902.1)	(38.9)%

Adjusted EBITDA from our Australian Mining segment was adversely affected during the year ended December 31, 2013 compared to the prior year by lower realized metallurgical and thermal coal pricing, net of sales-related costs ($686.1 million), costs associated with delays in the commissioning of longwall top coal caving technology and geologic issues at the North Goonyella Mine noted above ($116.0 million) and inflationary cost escalations ($61.8 million). Those factors were partially offset by the benefits of production efficiencies realized in the current year at several surface mining operations due to certain owner-operator conversions completed in April 2013 and comparatively favorable geologic conditions ($130.0 million) and the effect of our ongoing cost containment initiatives ($127.8 million). While tons sold increased by 5.8% in 2013 compared to the prior year, the resulting benefits were largely offset by lower weighted-average margins experienced across the platform.

Lower Western U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2013 compared to the prior year mainly reflected lower realized coal pricing, net of sales-related costs ($97.2 million), and a decline in tons sold ($73.1 million). Western U.S. Mining segment Adjusted EBITDA results for 2013 were also unfavorably impacted by higher costs associated with production-related commodities, net of hedging ($14.9 million). Those factors were partially offset by lower year-over-year expenditures related to materials and supplies, maintenance, labor and other operations support spending attributed to cost containment initiatives ($42.9 million).

Midwestern U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2013 was in line with results from the prior year. The negative effects of lower volumes and revenues discussed above and higher costs associated with production-related commodities, net of hedging ($21.6 million), were largely offset by a change in production mix toward lower-cost operations and other cost containment initiatives.

Trading and Brokerage segment Adjusted EBITDA for the year ended December 31, 2013 decreased compared to the prior year. In addition to the revenue items noted above, Trading and Brokerage results were adversely impacted in 2013 by a $20.6 million charge related to the Gulf Power litigation. Refer to Note 24. "Commitments and Contingencies" to the accompanying consolidated financial statements for additional information related to that matter, which information is incorporated herein by reference.

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Loss From Continuing Operations Before Income Taxes

The following table presents loss from continuing operations before income taxes for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Income	
	2013	2012	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$1,416.3	$2,318.4	$(902.1)	(38.9)%
Corporate and Other Adjusted EBITDA[1]	(369.1)	(481.9)	112.8	23.4%
Depreciation, depletion and amortization	(740.3)	(663.4)	(76.9)	(11.6)%
Asset retirement obligation expenses	(66.5)	(67.0)	0.5	0.7%
Asset impairment and mine closure costs	(528.3)	(929.0)	400.7	43.1%
Settlement charges related to the Patriot bankruptcy reorganization	(30.6)	—	(30.6)	n.m.
Amortization of basis difference related to equity affiliates	(6.3)	(4.6)	(1.7)	(37.0)%
Interest expense	(425.2)	(405.6)	(19.6)	(4.8)%
Interest income	15.7	24.5	(8.8)	(35.9)%
Loss from continuing operations before income taxes	$(734.3)	$(208.6)	$(525.7)	(252.0)%

(1) Corporate and Other Adjusted EBITDA includes selling and administrative expenses, income (losses) from equity affiliates, gains (losses) on certain asset sales, costs associated with past mining activities, certain coal royalty expenses, resource management costs and revenues and expenses related to our other commercial activities, such as generation development and Btu Conversion.

Results from continuing operations before income taxes for the year ended December 31, 2013 declined compared to the prior year. In addition to the decrease in Segment Adjusted EBITDA discussed above, our 2013 results reflect comparatively higher depreciation, depletion and amortization and interest expense, in addition to a settlement charge related to the bankruptcy reorganization of Patriot Coal Corporation (Patriot). Those negative factors were partially offset by lower asset impairment and mine closure costs and an improvement in Corporate and Other Adjusted EBITDA.

The favorable change in Corporate and Other Adjusted EBITDA during the year ended December 31, 2013 compared to the prior year reflected a second quarter 2013 gain on the sale of non-strategic coal reserves and surface lands in Kentucky ($40.3 million), lower postretirement health care costs due to favorable health care costs trend rates ($25.6 million), improved results from equity affiliates ($22.7 million) and reduced selling and administrative expenses resulting from our ongoing cost containment initiatives ($19.7 million). The improvement in results from equity affiliates was driven by the implementation of certain operational improvements at the Middlemount Mine in Queensland, Australia during the second half of 2013, which improvements included a conversion to owner-operator status. Those factors were partially offset by a charge of $20.0 million recorded in 2013 due to an increase in estimate of our undiscounted liabilities for environmental clean-up related costs associated with Gold Fields Mining, LLC, a dormant, non-coal producing entity that was previously managed and owned by our predecessor owner and transferred to us in a February 1997 spin-off.

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The following table presents a summary of depreciation, depletion and amortization expense by segment for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Income	
	2013	2012	$	%
	(Dollars in millions)			
Australian Mining	$(406.4)	$(344.0)	$(62.4)	(18.1)%
Western U.S. Mining	(220.2)	(209.5)	(10.7)	(5.1)%
Midwestern U.S. Mining	(80.4)	(81.6)	1.2	1.5 %
Trading and Brokerage	(0.7)	(0.7)	—	— %
Corporate and Other	(32.6)	(27.6)	(5.0)	(18.1)%
Total	$(740.3)	$(663.4)	$(76.9)	(11.6)%

Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments for the years ended December 31, 2013 and 2012:

	Year Ended December 31,	
	2013	2012
Australian Mining	$5.03	$5.32
Western U.S. Mining	0.81	0.69
Midwestern U.S. Mining	0.66	0.67

The increase in depreciation, depletion and amortization expense noted in the year ended December 31, 2013 compared to the prior year was predominantly driven by higher expense from our Australian Mining segment. That increase was primarily due to a year-over-year increase in tons sold, additional expense from growth and development projects completed in late 2012 and the depreciation of additional capital equipment acquired in connection with owner-operator conversions completed at certain mines in the second quarter of 2013. Those increases were partially offset by lower asset bases at certain sites due to asset impairment charges recognized in the fourth quarter of 2012. Depreciation, depletion and amortization expense in the year ended December 31, 2012 was affected by provisional fair value adjustments associated with our 2011 acquisition of Macarthur Coal Limited (PEA-PCI), which lowered expense by $9.2 million.

The increase in depreciation, depletion and amortization from our Western U.S. Mining segment during the year ended December 31, 2013 compared to the prior year reflected a shift in production mix toward higher depletion rate coal reserve locations, which more than offset the effect of the 3.9% decrease in tons sold.

Asset retirement obligation expenses for the year ended December 31, 2013 were in line with the prior year. The slight decrease was largely attributable to lower ongoing reclamation rates from our Western U.S. Mining segment due to favorable changes in cost trends and lower volumes, partially offset by the effect of increased production volumes from our Australian Mining segment and an increase in reclamation rates at certain of our Australian mines associated with recently completed expansion projects.

We recognized $528.3 million and $929.0 million in aggregate asset impairment and mine closure charges during the years ended December 31, 2013 and 2012, respectively. Refer to Note 2. "Asset Impairment and Mine Closure Costs" to the accompanying consolidated financial statements for further information regarding the nature and composition of those charges, which information is incorporated herein by reference.

Results from continuing operations before income taxes for the year ended December 31, 2013 included $30.6 million in before-tax charges associated with the settlement of claims and litigation related to the Patriot bankruptcy reorganization. Refer to Note 25. "Matters Related to the Bankruptcy of Patriot Coal Corporation" to the accompanying consolidated financial statements for additional information surrounding the related matters, which information is incorporated herein by reference.

Interest expense for the year ended December 31, 2013 included higher early debt extinguishment charges compared to the prior year ($13.6 million), which was mainly attributable to the 2013 Credit Facility that was entered into during the third quarter of 2013. Refer to the "Liquidity and Capital Resources" section below for additional information related to the 2013 Credit Facility. Interest expense also increased in 2013 due to higher interest rates associated with our term loan borrowings and $6.9 million in prejudgment interest recognized in the second quarter of 2013 associated with the Gulf Power litigation. Those factors were partially offset by the beneficial effect of lower average debt levels in the current year.

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Loss from Continuing Operations, Net of Income Taxes

The following table presents loss from continuing operations, net of income taxes, for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Income	
	2013	2012	$	%
	(Dollars in millions)			
Loss from continuing operations before income taxes	$(734.3)	$(208.6)	$(525.7)	(252.0)%
Income tax (benefit) provision	(448.3)	262.3	710.6	270.9%
Loss from continuing operations, net of income taxes	$(286.0)	$(470.9)	$184.9	39.3%

Loss from continuing operations, net of income taxes, for the year ended December 31, 2013 improved compared to the prior year, with the adverse changes in before-tax earnings discussed above more than offset by the positive effect of the overall income tax benefit recorded in 2013.

The year-over-year positive effect of income taxes in 2013 was driven by the following:

- A prior year increase in our valuation allowance against Australian ($332.2 million) and U.S. ($85.5 million) loss carryforwards based on changes in the estimated future realization of those carryforwards;
- The impact of lower current year earnings, including the income tax effects of asset impairment and mine closure costs and charges associated with the settlement of claims and litigation related to the Patriot bankruptcy reorganization ($210.3 million);
- Recoverable benefits (royalty allowance) recognized in 2013 related to the Australian minerals and resource rent tax (MRRT) ($148.4 million); and
- The impact from the remeasurement of non-U.S. tax accounts as a result of the current year weakening of the Australian dollar compared with strengthening in the prior year ($52.2 million), as set forth in the table below; partially offset by
- The recognition of a net tax benefit in 2012 due to the restructuring of foreign operations ($74.7 million), comprised of a realized U.S. capital loss benefit, net of valuation allowance, and a foreign tax benefit due to the tax basis reset required upon the PEA-PCI operations joining our Australian consolidated tax group.

	December 31,			Rate Change	
	2013	2012	2011	2013	2012
Australian dollar to U.S. dollar exchange rate (period end)	$0.8948	$1.0384	$1.0156	$(0.1436)	$0.0228

Adjusted Income From Continuing Operations

The following table presents Adjusted Income from Continuing Operations for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Income	
	2013	2012	$	%
	(Dollars in millions)			
Loss from continuing operations, net of income taxes	$(286.0)	$(470.9)	$184.9	39.3%
Asset impairment and mine closure costs	528.3	929.0	(400.7)	(43.1)%
Settlement charges related to the Patriot bankruptcy reorganization	30.6	—	30.6	n.m.
Income tax benefit related to asset impairment and mine closure costs	(112.8)	(227.3)	114.5	50.4%
Income tax benefit related to the settlement charges related to the Patriot bankruptcy reorganization	(11.3)	—	(11.3)	n.m.
Remeasurement (benefit) expense related to foreign income tax accounts	(44.3)	7.9	(52.2)	(660.8)%
Adjusted Income from Continuing Operations	$104.5	$238.7	$(134.2)	(56.2)%

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Adjusted Income from Continuing Operations decreased in the year ended December 31, 2013 compared to the prior year due to unfavorable year-over-year changes in Adjusted EBITDA and higher depreciation, depletion and amortization and interest expense, partially offset by the effect of income taxes, as discussed above.

Net Loss Attributable to Common Stockholders

The following table presents net loss attributable to common stockholders for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Income	
	2013	2012	$	%
	(Dollars in millions)			
Loss from continuing operations, net of income taxes	$(286.0)	$(470.9)	$184.9	39.3%
Loss from discontinued operations, net of income taxes	(226.6)	(104.2)	(122.4)	(117.5)%
Net loss	(512.6)	(575.1)	62.5	10.9%
Net income attributable to noncontrolling interests	12.3	10.6	(1.7)	(16.0)%
Net loss attributable to common stockholders	$(524.9)	$(585.7)	$60.8	10.4%

Net results attributable to common stockholders improved during the year ended December 31, 2013 compared to the prior year largely due to the favorable change in results from continuing operations, net of income taxes, discussed above, partially offset by the unfavorable impact of changes in results from discontinued operations.

Loss from discontinued operations for the year ended December 31, 2013 reflected before- and after-tax asset impairment and mine closure costs of $167.4 million and $117.2 million, respectively, recognized in connection with the closure of the Wilkie Creek Mine in Queensland, Australia. Results for that period also included before- and after-tax charges of $98.0 million and $61.8 million, respectively, associated with the settlement of claims and litigation related to the Patriot bankruptcy reorganization. Loss from discontinued operations for the year ended December 31, 2012 included before- and after-tax asset impairment and mine closure costs of $116.7 million and $75.0 million, respectively, recognized in connection with the closure of our former Air Quality Mine in Indiana. Additional information surrounding the aforementioned asset impairment and mine closure costs and charges for the settlement of claims and litigation related to the Patriot bankruptcy reorganization is included in Note 2. "Asset Impairment and Mine Closure Costs" and Note 25. "Matters Related to the Bankruptcy of Patriot Coal Corporation" to the accompanying consolidated financial statements, respectively, which information is incorporated herein by reference.

Diluted EPS

The following table presents diluted EPS for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2013	2012	$	%
Diluted EPS attributable to common stockholders:				
Loss from continuing operations	$(1.12)	$(1.80)	$0.68	37.8%
Loss from discontinued operations	(0.85)	(0.39)	(0.46)	(117.9)%
Net loss	$(1.97)	$(2.19)	$0.22	10.0%

Diluted EPS increased in the year ended December 31, 2013 compared to the prior year commensurate with the improvement in results from continuing operations between those periods, partially offset by higher losses from discontinued operations.

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Adjusted Diluted EPS

The following table presents Adjusted Diluted EPS for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2013	2012	$	%
Adjusted Diluted EPS Reconciliation:				
Loss from continuing operations	$(1.12)	$(1.80)	$0.68	37.8 %
Asset impairment and mine closure costs, net of income taxes	1.56	2.61	(1.05)	(40.2)%
Settlement charges related to the Patriot bankruptcy reorganization, net of income taxes	0.07	—	0.07	n/a
Remeasurement (benefit) expense related to foreign income tax accounts	(0.17)	0.03	(0.20)	(666.7)%
Adjusted Diluted EPS	$0.34	$0.84	$(0.50)	(59.5)%

Adjusted Diluted EPS for the year ended December 31, 2013 decreased compared to the prior year commensurate with the decline in Adjusted Income from Continuing Operations during that period.

Other

The net fair value of our foreign currency cash flow hedges decreased from a net asset of $286.9 million at December 31, 2012 to a net liability of $473.3 million at December 31, 2013 primarily due to the weakening of the Australian dollar relative to the U.S. dollar during that period. This change is reflected in “Other current assets,” “Investments and other assets,” "Accounts payable and accrued expenses" and “Other noncurrent liabilities” in the consolidated balance sheets.

The fair value of our coal trading positions designated as cash flow hedges of future sales, before the application of counterparty cash margin, decreased from a net asset of $153.1 million at December 31, 2012 to $62.9 million at December 31, 2013 due mainly to positions realized during that period.

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

Summary

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

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

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

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

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In spite of a modest year-over-year revenue increase of 2.3%, our Segment Adjusted EBITDA decreased by 9.4% compared to 2011 led by reductions in realized seaborne coal pricing ($432.7 million, net of sales-related costs), and lower U.S. volumes, partially offset by higher volumes from our Australian platform due to the fourth quarter 2011 acquisition of PEA-PCI and the benefits of mine expansions and higher contract pricing in the U.S.
(Loss) income from continuing operations, net of income taxes, changed unfavorably by $1,483.7 million in 2012 compared to the prior year due to lower Segment and Corporate and Other Adjusted EBITDA, increases in interest expense and depreciation, depletion and amortization resulting from the PEA-PCI acquisition and $929.0 million in charges related to asset impairments and mine closures. Year-over-year changes in our effective tax rate further reduced earnings in 2012 compared to 2011 due mainly to an increase in our valuation allowance against Australian loss carryforwards. Adjusted Income from Continuing Operations, which excludes the impacts of asset impairment and mine closure costs, net of tax, and the remeasurement of foreign income tax accounts, also decreased in 2012 compared to the prior year, though by a lesser amount of $773.2 million, or 76.4%.
Net (loss) income also decreased on a year-over-year basis in 2012 due to lower results from continuing operations and charges recognized in 2012 related to the closure of our Air Quality Mine, which is classified as a discontinued operation for all periods presented.
We ended 2012 with total available liquidity of approximately $2.2 billion.

Tons Sold

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

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

Revenues

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

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

Revenues from our Australian Mining segment increased in the year ended December 31, 2012 compared to the prior year due to the benefit of additional sales volumes ($910.3 million), which were driven by incremental year-over-year volume contributions from PEA-PCI mines acquired in the fourth quarter of 2011 ($508.8 million) and an overall production increase in our legacy Australian platform ($401.5 million). The year-over-year increase in our legacy platform production in 2012 resulted from the benefit of completed mine expansions at our Wilpinjong and Millennium mines, lower overall downtimes due to longwall moves and the adverse production effects experienced in the second half of 2011 due to a roof fall during the third quarter of that year, partially offset by production challenges from certain of our contractor-operated mines. The favorable volume variance in 2012 compared to 2011 was partially offset by an unfavorable price variance between those periods due to the impact of lower year-over-year average coal prices discussed above ($487.4 million). Metallurgical coal sales totaled 14.1 million and 9.3 million tons in 2012 and

2011, respectively, with the year-over-year increase largely attributable to incremental volumes contributed by PEA-PCI.

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Revenues from our Western U.S. Mining segment increased during the year ended December 31, 2012 compared to the prior year resulting mainly from higher contract pricing ($167.9 million). That favorable price variance was partially offset by the unfavorable net impact of sales volume and mix ($119.0 million). Demand from electric power generators served by this segment was adversely affected in 2012 compared to the prior year by competition from natural gas and a decrease in heating-degree days from mild winter weather. Those effects were only partially offset by a slight increase in heating-degree days in 2012 compared to 2011 due to warm summer weather.

Midwestern U.S. Mining segment revenues were relatively unchanged in the year ended December 31, 2012 compared to the prior year. Revenues from that segment benefited from higher contract prices in 2012 compared to 2011 ($70.6 million), the effect of which was almost entirely offset by the unfavorable net impact of sales volume and mix in 2012 versus the prior year ($69.5 million) due to soft U.S. coal market demand.

The decline in our Trading and Brokerage segment revenues during the year ended December 31, 2012 compared to 2011 was mainly driven by a comparatively higher portion of our contract revenue being recognized on a net basis in the current period due to the expiration of certain physical delivery contracts that were recognized on a gross basis in 2011 ($180.3 million). Revenues from that segment were also affected in 2012 compared to the prior year by lower realized prices on physical shipments and counterparty nonperformance under certain contracts.

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

Segment Adjusted EBITDA

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

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

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

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

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

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Trading and Brokerage segment Adjusted EBITDA for the year ended December 31, 2012 decreased compared to the prior year due to lower realized price margins on U.S. and Australian export volumes ($63.1 million).

(Loss) Income From Continuing Operations Before Income Taxes

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

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

(1) Corporate and Other Adjusted EBITDA includes selling and administrative expenses, income (losses) from equity affiliates, gains (losses) on certain asset sales, costs associated with past mining activities, certain coal royalty expenses, resource management costs and revenues and expenses related to our other commercial activities, such as generation development and Btu Conversion.

(Loss) income from continuing operations before income taxes for the year ended December 31, 2012 changed unfavorably compared to the prior year. In addition to the decrease in Segment Adjusted EBITDA discussed above, our results were negatively affected compared to 2011 by lower Corporate and Other Adjusted EBITDA, increased depreciation, depletion and amortization and higher asset retirement obligation expenses, asset impairment and mine closure costs and interest expense.

Corporate and Other Adjusted EBITDA was adversely impacted in 2012 by higher losses associated with our 50% interest in the newly operational Middlemount Mine acquired as part of the PEA-PCI acquisition compared to the prior year ($41.4 million), which were affected in 2012 by unfavorable metallurgical coal pricing and contractor mining issues. Corporate and Other Adjusted EBITDA also declined during 2012 compared to the prior year as a result of gains recognized in 2011 related to non-cash exchanges of coal reserves in Kentucky and coal reserves and surface lands in Illinois for coal reserves in West Virginia ($37.7 million) and sales of non-strategic coal reserves in Kentucky ($31.7 million) executed during that period, in addition to our prior year receipt of a project development fee related to our involvement in Prairie State ($14.6 million). The effect of those factors was partially offset by the impact of costs incurred during 2011 related to the acquisition of PEA-PCI ($85.2 million) that did not recur in 2012.

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The following table presents a summary of depreciation, depletion and amortization expense by segment for the years ended December 31, 2012 and 2011:

	Year Ended December 31,		Increase (Decrease) to Income	
	2012	2011	$	%
	(Dollars in millions)			
Australian Mining	$(344.0)	$(181.6)	$(162.4)	(89.4)%
Western U.S. Mining	(209.5)	(204.5)	(5.0)	(2.4)%
Midwestern U.S. Mining	(81.6)	(68.1)	(13.5)	(19.8)%
Trading and Brokerage	(0.7)	(0.6)	(0.1)	(16.7)%
Corporate and Other	(27.6)	(19.5)	(8.1)	(41.5)%
Total	$(663.4)	$(474.3)	$(189.1)	(39.9)%

Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments for the years ended December 31, 2012 and 2011:

	Year Ended December 31,	
	2012	2011
Australian Mining	$5.32	$3.45
Western U.S. Mining	0.69	0.63
Midwestern U.S. Mining	0.67	0.56

Depreciation, depletion and amortization expenses increased during the year ended December 31, 2012 compared to the prior year due to incremental expenses associated with PEA-PCI mines acquired in the fourth quarter of 2011 ($108.3 million) and higher expenses from our legacy Australian mining platform caused by increased depletion rates and higher overall production ($54.1 million). Also impacting the increase in 2012 compared to the prior year were additional expenses from our Midwestern U.S. Mining and Corporate and Other segments from the continued expansion of our Bear Run Mine and the 2012 commencement of commercial operations at Prairie State, respectively.

Asset retirement obligation expenses were higher in the year ended December 31, 2012 compared to 2011. The increase was largely attributable to incremental expense associated with acquired PEA-PCI mines and the impact of 2012 reclamation plan changes at certain of our U.S. mines.

We recognized $929.0 million in aggregate asset impairment and mine closure charges during 2012, which contributed significantly to the unfavorable year-over-year decrease in earnings observed in that period. Refer to Note 2. "Asset Impairment and Mine Closure Costs" to the accompanying consolidated financial statements, which is incorporated herein by reference, for further information regarding the nature and composition of the charges.

Additional debt incurred in connection with the PEA-PCI acquisition resulted in higher interest expense during the year ended December 31, 2012 compared to the prior year. The impact of those expenses was partially offset by the effect of interest expense associated with bridge financing obtained during 2011 in support of that acquisition.

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

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

	Year Ended December 31,		Increase (Decrease) to Income	
	2012	2011	$	%
	(Dollars in millions)			
(Loss) income from continuing operations before income taxes	$(208.6)	$1,376.0	$(1,584.6)	(115.2)%
Income tax provision				