PEABODY ENERGY CORP
Form 10-K
February 25, 2015
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, 2014
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. þ
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 ¨   Smaller reporting company ¨
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No 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, 2014: Common Stock, par value $0.01 per share, $4.4 billion.

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of February 20, 2015: Common Stock, par value $0.01 per share, 274,817,605 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 2015 Annual Meeting of Shareholders (the Company's 2015 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 oth 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:

- supply and demand for our coal products;
- price volatility and customer procurement practices, particularly in international seaborne 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 and production;
- 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;
- adequate liquidity and the cost, availability and access to capital and financial markets;
- ability to appropriately secure our obligations for reclamation, federal and state workers' compensation, federal coal leases and other obligations related to our operations;
- 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, including cybersecurity 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

We are the world’s largest private-sector coal company. As of December 31, 2014, we owned interests in 26 active coal mining operations located in the United States (U.S.) and Australia. We have a majority interest in 25 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 Australia, China, Germany, India, Indonesia, Singapore, the United Kingdom and the U.S. (listed alphabetically).

Mission and Strategy

Our mission statement is: "To create superior value for shareholders as the leading global supplier of coal, which enables economic prosperity and a better quality of life." We seek to do so while remaining committed to our values of safety, customer focus, leadership, people, excellence, integrity and sustainability. Our strategy to achieve our mission is to (1) maintain a leading position in the U.S. coal basins that we have identified as higher-growth and lower-cost compared with other U.S. coal basins or in U.S. regions in which we are otherwise strategically positioned; (2) continue to develop our metallurgical and thermal coal platform in Australia; and (3) expand our global presence, particularly in Asian coal market segments.

In support of that strategy, we have outlined the following strategic priorities for managing our businesses:

- Drive safety, productivity and cost-efficiency across our operating platform;
- Strengthen our financial position through disciplined capital investment and revenue growth, while maintaining financial flexibility;
- Enhance the quality of our assets, using our coal reserves to feed our project pipeline and capture growth and development opportunities;
- Advocate for increased global understanding and support for coal mining and use, favorable energy policy and advances in related technologies; and
- Employ talented personnel and align their talents with our mission to maximize our collective opportunity for success.

History and Development

We were incorporated in Delaware in 1998 and became a public company in 2001. Our history in the coal 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.

In 2014, we advanced multiple operational and capital projects focused on operational efficiency and maintaining a competitive position in the market segments in which we operate. Such advancements included (1) completing the commissioning and post start-up modifications of longwall top coal caving technology at our North Goonyella Mine in Australia; (2) advancing the reserve development at the planned Gateway North Mine in the U.S. to replace production from the existing Gateway Mine as its reserves are exhausted in 2015; (3) installing a new longwall to increase productivity at the Metropolitan Mine in Australia; (4) converting the Moorvale Mine in Australia to owner-operator status; and (5) continuing our ongoing cost containment initiatives across our global platform response to challenged global coal market segment conditions.

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In 2014, we also agreed to establish a joint venture project with Glencore plc (Glencore), in which each party will hold a 50% interest, to combine the existing operations of our Wambo Open-Cut Mine in Australia with the adjacent coal reserves of Glencore's United Mine. We expect the project to result in several operational synergies, including improved mining productivity, lower per-unit operating costs and an extended mine life. The joint venture operations are expected to commence in 2017, subject to regulatory permitting.

In 2015, we plan to maintain a tightly controlled approach to capital deployment as we continue to navigate through the challenged global coal industry conditions. Anticipated capital and operational projects will again mainly focus on driving improvements in safety and operational efficiency and preserving the productive capacity of our existing mining platform.

We will continue to explore opportunities to expand our presence in Asia 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.

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 and activities associated with the optimization of our coal reserve and real estate holdings, the closure of inactive mining sites and certain energy-related commercial matters.

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, 2014. 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.

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Our Western U.S. Mining segment is comprised of our Powder River Basin, Southwest and Colorado active 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.

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 mines that were active in 2014 in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2014.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Primary Transport Method	2014 Tons Sold (In millions)
Western U.S. Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	118.1
Rawhide	Wyoming	S	D, T/S	T	R	15.5
El Segundo	New Mexico	S	D, DL, T/S	T	R	8.2
Kayenta	Arizona	S	DL, T/S	T	R	8.2
Caballo	Wyoming	S	D, T/S	T	R	8.0
Twentymile	Colorado	U	LW	T	R, Tr	7.1
Lee Ranch	New Mexico	S	T/S	T	R	0.3
Other (1)	—	—	—	—	—	1.0
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	Tr, R	8.6
Francisco Underground	Indiana	U	CM	T	R	3.1
Gateway	Illinois	U	CM	T	Tr, R, R/B, T/B	2.5
Wild Boar	Indiana	S	D, T/S	T	Tr, R, R/B, T/B	2.2
Wildcat Hills Underground	Illinois	U	CM	T	T/B	1.9
Somerville Central	Indiana	S	DL, D, T/S	T	R, R/B, T/B, T/R	1.8
Cottage Grove	Illinois	S	D, T/S	T	T/B	1.7
Somerville North (2)	Indiana	S	D, T/S	T	Tr, R, R/B, T/B, T/R	1.6
Somerville South (2)	Indiana	S	D, T/S	T	Tr, R, R/B, T/B,	1.3
Viking - Corning Pit (3)	Indiana	S	D, T/S	T	Tr, T/R	0.2
Other (1)	—	—	—	—	—	0.1
Australian Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	13.8
Millennium	Queensland	S	D, T/S	M, P	R, EV	3.8
Wambo Open-Cut (2)	New South Wales	S	T/S	T	R, EV	3.8
Coppabella (4)	Queensland	S	DL, D, T/S	P	R, EV	3.4
North Wambo Underground (2)	New South Wales	U	LW	T, P	R, EV	3.4
North Goonyella	Queensland	U	LTCC	M	R, EV	2.5
Metropolitan	New South Wales	U	LW	M	R, EV	2.4
Burton *	Queensland	S	T/S	M, T	R, EV	2.1
Moorvale (4)	Queensland	S	T/S	M, P	R, EV	2.1
Eaglefield * (3)	Queensland	S	T/S	M	R, EV	0.9
Middlemount (5)	Queensland	S	T/S	M, P	R, EV	—

Legend:

S	Surface Mine	R	Rail
U	Underground Mine	Tr	Truck
DL	Dragline	R/B	Rail to Barge
D	Dozer/Casting	T/B	Truck to Barge
T/S	Truck and Shovel	T/R	Truck to Rail
		EV	Export Vessel

LW	Longwall	T	Thermal/Steam
LTCC	Longwall Top Coal Caving	M	Metallurgical
CM	Continuous Miner	P	Pulverized Coal Injection
*	Mine 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 ceased production in 2014 due to the exhaustion of reserves.

(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, 2014 tons sold from that mine, which totaled 3.7 million tons (on a 100% basis), 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 the trading and business offices mentioned previously. Coal brokering is conducted both as principal and agent in support of various coal production-related activities that may involve coal produced from our mines, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. Our Trading and Brokerage segment also provides transportation-related services, which involves both financial derivative contracts and physical contracts. Collectively, coal and freight-related hedging activities include both economic hedging and cash flow hedging in support of our coal trading strategy, and cash flow hedging 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 other energy-related commercial activities.

Resource Management. As of December 31, 2014, we held approximately 7.6 billion tons of proven and probable coal reserves and approximately 500 thousand acres of surface property through ownership and lease agreements. We have an ongoing asset optimization program whereby our property management 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 Middlemount Coal Pty Ltd., which owns 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 first commenced at the Middlemount Mine in late 2011 and the mine continued to ramp up production and implement operational improvements through 2014. During the years ended December 31, 2014, 2013 and 2012, the mine sold 3.7 million, 2.8 million and 1.9 million tons of coal, respectively (on a 100% basis).

Singapore Joint Venture. In 2013, we announced an agreement with Shenhua Group Corporation Limited (Shenhua), a large-scale state-owned energy company headquartered in Beijing, China, to form Sino-Pacific Coal Trading Corporation Pte. Ltd. (Sino-Pacific), a Singapore-based joint venture in which we would retain a 50% interest. The parties to the agreement no longer intend to move forward with the joint venture.

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.

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.

Captive Insurance Entity. A portion of our insurance risks associated with workers’ compensation, general liability and auto liability coverage is self-insured through a wholly-owned captive insurance company. The captive entity also issues our global property insurance policy, with the related risk ceded to the commercial insurance market in its entirety. This captive entity invoices certain of our subsidiaries for the premiums on these policies, pays the related claims, maintains reserves for anticipated losses and invests funds to pay future claims. Historically, the actuarially-determined reserves maintained by our captive entity have provided adequate coverage of actual claims incurred.

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Clean Coal Technology. We continue to support clean coal technology development and 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 launched by the Australian government. In the U.S., we are a founding member of the FutureGen Alliance in Illinois and continue to support the development of the FutureGen 2.0 project. We are also a founding member of the Consortium for Clean Coal Utilization at Washington University in St. Louis and support technology development at the University of Wyoming School of Energy Resources. In addition to our support of clean coal technology development, we are evaluating Btu Conversion projects that are designed to expand the uses of coal, such as through conversion to transportation fuels and coal gasification technologies.

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 initial terms longer than one year and which often include price reopener and/or extension provisions). A smaller portion of our sales are made under contracts with terms of less than one year, including sales made on a spot basis. Sales under long-term coal supply agreements comprised approximately 83%, 80% and 89% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2014, 2013 and 2012, respectively.

For the year ended December 31, 2014, we derived 25% of our total revenues from our five largest customers. Those five customers were supplied primarily from 41 coal supply agreements (excluding trading transactions) expiring at various times from 2015 to 2026. The contract contributing the greatest amount of annual revenue in 2014 was approximately $350 million, or approximately 5% of our 2014 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 800 million and 900 million tons of coal as of January 1, 2015 and 2014, respectively. Contracts in backlog have remaining terms ranging from one to 13 years and represent approximately four years of production based on our 2014 production volume of 227.2 million tons. Approximately 77% of our backlog is expected to be filled beyond 2015.

U.S. Mining Operations. Revenues from our Western and Midwestern U.S. Mining segments, in aggregate, represented approximately 59%, 57% and 54% of our total revenue base for the years ended December 31, 2014, 2013 and 2012, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 83%, 84% and 85% 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.

Australian Mining Operations. Revenues from our Australian Mining segment represented approximately 39%, 41% and 43% of our total revenue base for the years ended December 31, 2014, 2013 and 2012, respectively, during which periods the coal mining activities of that segment contributed respective amounts of 17%, 16% and 15% 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, which portion has increased in recent years.
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).

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

Export Facilities. Our U.S. Mining operations exported approximately 1%, 2% and 3% of its tons sold for the years ended December 31, 2014, 2013 and 2012, respectively. Our primary ports used for U.S. exports are 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. In connection with our Trading and Brokerage operations, we also utilize the Dominion Terminal Associates coal terminal in Newport News, Virginia to export coal sourced from domestic third-party producers. We are continuing to assess opportunities for access to West Coast port facilities that will allow us to export our Powder River Basin coal products to serve demand in the Asian region, should market conditions warrant.

Our Australian Mining operations sold approximately 77%, 75% and 77% of its tons into the seaborne coal markets for the years ended December 31, 2014, 2013 and 2012, respectively. We have generally secured our ability to transport coal in Australia through rail and port contracts and interests in three east coast coal export terminals that are primarily funded through take-or-pay arrangements (Refer to 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 on our take-or-pay obligations). 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.

Surface and underground mining equipment demand and lead times have remained suppressed in recent periods 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 the Mine Safety and Health Administration (MSHA) and other government agencies to identify and test emerging safety technologies. 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 exploring, implementing or using leading technology to assist with proximity detection and fatigue monitoring.

We pursue 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 suppliers to design and produce equipment that we believe will improve our safety, operating performance and mining capabilities.

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We seek to deploy the best mining technologies available based on the specific geologic conditions of each of our mining operations. For example, we completed the commissioning of longwall top coal caving technology at our North Goonyella Mine in Australia in 2014.

We leverage technology and data systems to enhance our operating and maintenance efforts through the integration of original equipment manufacturer systems, mobile technology solutions and automated reporting systems to provide an integrated, real time picture of our mining operations and equipment performance. We continue to advance the use of technology applications to schedule trains, monitor coal quality and customer shipments and manage mine operations and pit blending to enhance 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 equipment life, while reducing 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 to continually improve component life, operator training and equipment reliability.

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. Metallurgical coal demand is also impacted by competing technologies used to make steel, some of which do not use coal as a manufacturing input. 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., the Cline Group and Cloud Peak Energy Inc., who collectively accounted for approximately 37% of total U.S. coal production in 2013 according to the National Mining Association's "2013 Coal Producer Survey," the most recent data publicly available as of February 25, 2015. Major international direct competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Glencore PLC, PT Bumi Resources Tbk., 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.

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 2014 that coal's share of worldwide electric power generation mix was 41% in 2012. 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. 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 $2.50 to $2.75 per mmBtu and $3.50 to $3.75 per mmBtu, respectively, and to decline when natural gas prices fall below those levels. The U.S. Energy Information Administration (EIA) reported in its February 2015 "Short-Term Energy Outlook" that coal's share of U.S. electricity generation for all sectors was 38.9% in 2014, in line with 39.1% in the prior year. While electricity generation from coal benefited from an 18% year-over-year increase in full year average U.S. natural gas prices to $4.39 per mmBtu during 2014, that favorable impact was offset by the effect of coal conservation efforts employed by electricity generators in response to poor rail performance. The EIA expects full year average U.S. natural gas prices to fall to $3.05 per mmBtu in 2015, partly driving a corresponding decrease in coal's projected share of U.S. electricity generation for all sectors to 37.8% 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 (as amended, the 2013 Revolver) under our secured credit agreement entered into in 2013 (as amended, 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.

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Employees

We had approximately 8,300 employees as of December 31, 2014, including approximately 6,000 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 [(1)]
Gregory H. Boyce	60	Chairman and Chief Executive Officer
Glenn L. Kellow	47	President and Chief Executive Officer-elect
Michael C. Crews	47	Executive Vice President and Chief Financial Officer
Bryan A. Galli	54	Group Executive and Chief Marketing Officer
Christopher J. Hagedorn	42	Group Executive and Chief Development Officer
Jeane L. Hull	60	Executive Vice President and Chief Technical Officer
Charles F. Meintjes	52	President - Australia
Alexander C. Schoch	60	Executive Vice President Law, Chief Legal Officer and Secretary
Andrew P. Slentz	53	Executive Vice President and Chief Human Resources Officer
Kemal Williamson	55	President - Americas

[(1)] As of February 20, 2015.

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 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 and our President and Chief Executive Officer-elect in January 2015, at which time he also became a director of the Company. He has executive responsibility for all aspects of our global operations including safety, environment, production, sales and marketing, 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 U.S. National Mining Association, and a past member of the executive committee of the Western Australian Chamber of Minerals and Energy and the advisory board of the Energy and Mining Institute of the University of Western Australia. Mr. Kellow also was the Chairman of Worsley Alumina (Australia), Chairman of Mozal (Mozambique) and Chairman of the global 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. He holds an honorary Doctor of Science degree from the South Dakota School of Mines and Technology.

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Michael C. Crews was named our Executive Vice President and Chief Financial Officer in June 2008. He joined us in 1998 as Senior Manager of Financial Reporting, and has served as Assistant Corporate Controller, Director of Planning, Assistant Treasurer, Vice President of Planning, Analysis and Performance Assessment and Vice President of Operations Planning. Prior to joining us, Mr. Crews served for three years in financial positions with MEMC Electronic Materials, Inc. and six years at KPMG Peat Marwick in St. Louis. Mr. Crews serves on the Board of Directors of the St. Louis Regional Chamber. Mr. Crews has a Bachelor of Science degree in Accountancy from the University of Missouri at Columbia, a Master of Business Administration degree from Washington University in St. Louis and is a Certified Public Accountant in the State of Missouri.
Bryan A. Galli was named our Group Executive and Chief Marketing Officer in March 2014. He has executive responsibility for our Global Marketing and Trading Group, with oversight of sales, marketing, logistics and trading and brokerage activities across the global enterprise. He most recently served as our Group Executive of Sales and Marketing - Australia, and previously served as President of COALSALES, Group Executive for Midwest Operations and Vice President of Sales and Marketing for COALSALES in the Midwestern U.S. Mr. Galli holds a Bachelor of Science in mining engineering from the School of Mines at the University of Missouri (Rolla) (now called the Missouri University of Science and Technology), and serves as a member of its Mining Engineering Foundation Board.
Christopher J. Hagedorn was named our Group Executive and Chief Development Officer in March 2014. He has executive responsibility for our Global Development and Strategy Group, which includes global market analytics, strategy, portfolio optimization and business development activities, along with emerging opportunities. He most recently served as our President - Asia and Trading, and previously served as our Senior Vice President Global Sales and Trading Support, 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 and a member of St. Louis Children’s Hospital Board of Trustees.
Jeane L. Hull was named our Executive Vice President and Chief Technical Officer in March 2011. In her role, she leads supply chain management activities as well as technical, project and operations support functions across our global platform. 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 serves as a council member of the University of Wyoming School of Energy Resources Council. She also serves on the advisory board for the South Dakota School of Mines and Technology and the industry advisory board for the mining department at the Missouri University of Science and Technology. Ms. Hull serves on the board of directors of Interfor, a Toronto Stock Exchange listed lumber company with operations in Canada and the U.S.
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.

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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; NorthSide Community School, St. Louis, Missouri; and Case Western Reserve University Law Alumni Association, Cleveland, Ohio.

Andrew P. Slentz was named our Executive Vice President and Chief Human Resources Officer in April 2014. He has executive responsibility for organizational and employee development, benefits, compensation, international human resources, security, travel and facilities management. Mr. Slentz joined us in June 2010 as our Senior Vice President of Global Human Resources. Prior to joining us, he held senior human resource positions in the natural resources and telecommunications industries, including serving as Senior Vice President of Human Resources for People & Organization Support at Rio Tinto, Head of Human Resources for Drummond Company and Vice President of Human Resources, Commercial Development and Shared Services for BHP Billiton. Mr. Slentz holds a bachelor’s degree from Hamilton College and a master’s degree in industrial and labor relations from Cornell University.

Kemal Williamson was named our President - Americas in October 2012. He has executive responsibility for our U.S. operating platform. He oversees the areas of health and safety, operations, product delivery and support functions. Mr. Williamson has more than 30 years of 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 for two years at Cyprus Australia Coal Corporation as Director of Operations and managed coal operations in Australia for half a decade. He also has mining engineering, financial analysis and management experience across Colorado, Kentucky and Illinois. Mr. Williamson holds a Bachelor of Science degree in mining engineering from Pennsylvania State University as well as a Master of Business Administration degree from the Kellogg School of Management, Northwestern University in Evanston, Illinois.

Regulatory Matters — U.S.

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

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

Mine Safety and Health

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

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

MSHA has 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.

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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; however, the approval rate has increased following implementation of black lung provisions contained in the Affordable Care Act. 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.

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 2015. 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 April 2015. These OSM rulemakings and others could have a direct impact on our operations.
Clean Air Act (CAA). The CAA, enacted in 1970, and comparable state and tribal laws that regulate air emissions affect our U.S. coal mining operations both directly and indirectly.

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Direct impacts on coal mining and processing operations may occur through the CAA 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 CAA 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 EPA has adopted more stringent NAAQS for PM, nitrogen oxide and sulfur dioxide. In November 2014, the EPA proposed a more stringent NAAQS for ozone. Issuance of the proposed rule complies with a decision of the U.S. District Court for the Northern District of California in April 2014 ordering 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.

Proposed NSPS for Fossil Fuel-Fired Electricity Utility Generating Units (EGUs). On April 13, 2012, the EPA published for comment a proposed NSPS for emissions of carbon dioxide for new fossil fuel-fired EGUs (proposed NSPS for new power plants). On September 20, 2013, the EPA revoked its April 13, 2012 proposal and issued a new proposed NSPS for new power plants, using section 111(b) of the CAA. On January 8, 2014, the re-proposal was published in the Federal Register and the comment deadline was set at March 10, 2014. In the February 26, 2014 Federal Register, the EPA issued a Notice of Data Availability (NODA) and technical support document in support of the proposed NSPS for new power plants. After extensions, the public comment period for the re-proposed NSPS for new power plants and NODA closed on May 9, 2014. We believe that any final rules issued by the EPA will be challenged.

Proposed Rules for Regulating Carbon Dioxide Emissions From Existing Fossil Fuel-Fired EGUs. On June 2, 2014, the EPA issued and later formally published for comment proposed rules for regulating carbon dioxide emissions from existing fossil fuel-fired EGUs under section 111(d) of the CAA. The public comment period on the proposed rules closed on December 1, 2014. The proposed rules would require that the states individually or collectively create systems that would reduce carbon emissions from any EGU located within their borders. Individual states would have to submit their proposed implementation plans to the EPA within one year after the publication of the final rule. Overall, the proposed rules would attempt to achieve by 2020 a nationwide carbon dioxide reduction of 25% from 2005 baseline emissions and, by 2030, a reduction of 30% from 2005 baseline emissions. The EPA has indicated that it intends to adopt final rules by not later than June 1, 2015. We believe that any final rules issued by the EPA will be challenged.

Judicial Challenge to the EPA's Greenhouse Gas (GHG) Regulations. In December 2009, the EPA published its finding that atmospheric concentrations of greenhouse gases endanger public health and welfare within the meaning of the CAA, 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 CAA. In May 2010, the EPA published final greenhouse gas emission standards for new motor vehicles pursuant to the CAA. 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. On October 15, 2013, the U.S. Supreme Court agreed to review the federal government’s power to regulate GHGs from fixed sources. Six petitions were accepted for review, but a single question was being considered: “Whether the EPA permissibly determined that its regulation of

GHG emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases." The U.S. Supreme Court decision issued on June 23, 2014 reversed, in part, and affirmed, in part, the 2012 decision of the D.C. Circuit that upheld the EPA's series of CAA GHG-related regulations. Specifically, the court held that the EPA exceeded its statutory authority when it interpreted the CAA to require PSD and Title V permitting for stationary sources based on their potential GHG emissions. The court noted, however, that the EPA permissibly determined that a source already subject to the PSD program because of its emission of conventional pollutants may be required to limit its GHG emissions by employing the best available control technology for GHGs.

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Published sources indicate that most of the greenhouse gas emissions that the EPA's challenged rules contemplated regulating may continue to be regulated after the U.S. Supreme Court's decision is given effect. Motions by industry groups, certain states, environmental groups and the EPA have since been filed in the D.C. Circuit regarding the effect of the U.S. Supreme Court's decision on existing EPA regulations regarding GHG emissions, with industry groups and certain states asserting that the EPA must undertake new rulemaking if it wishes to regulate the GHG emission sources that the U.S. Supreme Court decided were within the EPA's authority to regulate, and the EPA and environmental groups contending that no new rulemaking is required.

Other judicial challenges include actions filed in the D.C. Circuit against the EPA's proposed rule for regulating carbon dioxide emissions from existing fossil fuel-fired EGUs. One action by an industry plaintiff and another by a coalition of states led by West Virginia assert that the EPA does not have the authority to issue the regulations of existing power plants under section 111(d) of the CAA that it has proposed, although the particulars of the arguments in the two challenges differ. The same industry plaintiff has also filed a claim, which is pending in U.S. District Court for the Northern District of West Virginia, asserting that the EPA has a nondiscretionary duty under the CAA to evaluate potential losses of or shifts in employment in conjunction with regulatory action and seeking an injunction barring the EPA Administrator from promulgating new regulations affecting the coal industry before completing the actions it asserts are required.

Cross State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA finalized the CSAPR, which requires the District of Columbia and 27 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 was expected to continue administering the Clean Air Interstate Rule until the pending challenges are resolved. The court vacated the CSAPR on August 21, 2012, in a two to one decision, concluding that the rule was beyond the EPA's statutory authority. The U.S. Supreme Court on April 29, 2014 reversed the D.C. Circuit and upheld the CSAPR, concluding generally that the EPA's development and promulgation of CSAPR was lawful, while acknowledging the possibility that under certain circumstances some states may have a basis to bring a particularized, as-applied challenge to the rule. In October 2014, the D.C. Circuit filed an order lifting its stay of CSAPR and addressing a number of preliminary motions regarding the implementation of the Supreme Court's remand. Oral argument on the case on remand in the D.C. Circuit is now scheduled for February 25, 2015.

Mercury and Air Toxic Standards (MATS). On December 16, 2011, the EPA announced the MATS rule and published it in the Federal Register on February 16, 2012. The MATS rulemaking collectively revised the NSPS for nitrogen oxides, sulfur dioxides and particulate matter for new and modified coal-fueled electricity generating plants, and imposed Maximum Achievable Control Technology (MACT) emission limits on hazardous air emissions from new and existing coal-fueled and oil-fueled electric generating plants. The rule provides three years for compliance and a possible fourth year as a state permitting agency may deem necessary. Some utilities have been moving forward with installation of equipment necessary to comply with MATS, and the EPA and states have been granting additional time beyond the 2015 deadline (but no more than one extra year) for facilities that need more time to upgrade and complete those installations. The rule will likely result in the retirement of certain older coal plants. The D.C. Circuit upheld the NSPS portion of the rulemaking in a unanimous decision on March 11, 2014, and upheld the limits on hazardous air emissions against all challenges on April 15, 2014, in a two-to-one decision. Industry groups and a number of states filed and were granted review of the D.C. Circuit decision in the U.S. Supreme Court. The case will be argued in 2015, with a decision anticipated by June 2015.

Clean Water Act (CWA). The CWA 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 CWA 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 CWA 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.

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A draft rule that clarifies waters protected by the CWA was proposed by the EPA in June of 2014. If the rule continues forward, it should be finalized in 2015. This rule is highly controversial and 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. On December 19, 2014, the EPA announced the final rule on coal combustion residuals (that is, coal ash). As finalized, the rule continues the exemption of CCR from regulation as a hazardous waste, but does impose new requirements at existing CCR surface impoundments and landfills that will need to be implemented over a number of different time-frames in the coming months and years, as well as at new surface impoundments and landfills. Generally these requirements will increase the cost of CCR management, but not as much as if the rule had regulated CCR as hazardous. This EPA initiative is separate from the OSM CCR rulemaking mentioned above.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Although generally not a prominent environmental law in 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 costs or our ability to mine some of our properties in accordance with our current mining plans.

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. 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 is expected to finalize an ammonium nitrate security program rule in 2015. The OSM has also recently initiated a rulemaking addressing nitrous clouds that may be produced during blasting. 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.

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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 extract the resource 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 Conservation Act 1999, Native Title Act 1993, Fair Work Act 2009 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, Sustainable Planning Act 2009, 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, Work Health and Safety (Mines) Act 2013, 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 (Road and Rail Transport) 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 instruments must be considered when approving a mining project development application. There are multiple State Environmental Planning Policies (SEPPs) relevant to coal projects in New South Wales. Amendments to the SEPPs that cover mining have occurred in the past two years and are aimed at protecting agriculture, water resources and critical industry clusters. One SEPP, referred to as the Mining SEPP, was amended in late 2013 and makes it mandatory for decision makers to consider the economic significance of coal resources when determining a mine project development application.

Occupational Health and Safety. State legislation requires us to provide and maintain a safe workplace 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.

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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. 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 Australian dollars per tonne from 10% to 12.5% for pricing up to $150 Australian dollars per tonne and 15% on pricing over $150 Australian dollars per tonne. There was no change to the 7% rate for coal sold below $100 Australian dollars per tonne. The periodic impact of these royalty rates is dependent upon the volume of tonnes produced at each of our Queensland mining locations and coal prices received for those tonnes.

New South Wales Royalty. In New South Wales, the royalty applicable to coal is charged as a percentage of the value of production (total revenue less allowable deductions). This is equal to 6.2% for deep underground mines (coal extracted at depths greater than 400 meters below ground surface), 7.2% for underground mines and 8.2% for open-cut mines.

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 rise by 2.5% per year over a three year period and transition to an emissions trading scheme after June 30, 2015. All of our Australian operations were 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). On July 16, 2014, Australia's Senate voted to repeal the legislation, which was retrospectively abolished from July 1, 2014. Net of transition benefits, we recognized expense related to the carbon pricing framework of approximately $25 million, $40 million and $15 million in 2014, 2013 and 2012, respectively. Accordingly, we anticipate a modest improvement in our future operating costs and expenses as a result of the repeal of this legislation.

Minerals Resource Rent Tax (MRRT). On March 29, 2012, Australia passed legislation creating the MRRT effective from July 1, 2012. The MRRT was a profits-based tax on existing and future Australian coal and iron ore projects at an effective tax rate of 22.5%. Under the MRRT, taxpayers were able to deduct state royalties and depreciation of asset starting bases for existing projects against MRRT. On September 1, 2014, the Australian Senate voted to repeal the MRRT, and the legislation was prospectively abolished from October 1, 2014, with the final year of assessment ending on September 30, 2014. Upon the repeal of the MRRT, we wrote-off deferred tax assets of $70.1 million, including $54.0 million of royalty allowance credits recognized during the first half of 2014. Undeducted state royalties comprised the majority of those deferred tax assets.

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) and establishes stringent organizational, business conduct and prudential requirements for these CCPs. EMIR further requires margining for uncleared trades for certain parties. 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.

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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. - Environmental Laws and Regulations.”

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.

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 and fugitive emissions from the extraction of coal.

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 and the Japanese Bank for International Cooperation, have continued 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 has never been 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 Durban meeting, an ad hoc working group was established to develop a protocol, another legal instrument or an agreed outcome with legal force under the convention, applicable to all parties. 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. In December 2012, Australia signed on to the second commitment period.

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 July 16, 2014, Australia's Parliament repealed the legislation, which was retrospectively abolished from July 1, 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.

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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.

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 and production costs 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, using 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.

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

Most of our sales are made under coal supply agreements, which are important to the stability and profitability of our operations. The execution of a satisfactory coal supply agreement is frequently the basis on which we undertake the development of coal reserves required to be supplied under the contract, particularly in the U.S.

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.

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, 2014, we derived 25% of our total revenues from our five largest customers, similar to the prior year. Those five customers were supplied primarily from 41 coal supply agreements (excluding trading transactions) expiring at various times from 2015 to 2026. The contract contributing the greatest amount of annual revenue in 2014 was approximately $350 million, or approximately 5% of our 2014 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 2014 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 higher-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.

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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, 2014, 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.

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 $2.8 billion, with terms ranging up to 25 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 variable 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 and

2014, 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.

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

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

We enter into hedging arrangements designed primarily to manage market price volatility of foreign currency (primarily the Australian dollar), diesel fuel and coal. Also, from time to time, we manage the interest rate risk associated with our variable and fixed rate borrowings and commodity price risk associated with explosives using 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 and coal.

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 $154.4 million, $528.3 million and $929.0 million in 2014, 2013 and 2012, respectively. Because of the volatile and cyclical 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.

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

As of December 31, 2014, we had approximately 8,300 employees, which included approximately 6,000 hourly employees. Approximately 39% of our hourly employees were represented by organized labor unions and generated 20% of 2014 coal production. Additionally, those employed through contract mining relationships in Australia are also members of trade unions. Relations with our employees and, where applicable, organized labor are important to our success. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs. Also, if we fail to maintain good relations with our union workforce, we could experience labor disputes, work stoppages or other disruptions in production that could negatively impact our profitability.

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

U.S. federal and state laws and Australian laws require us to secure certain of our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, to secure coal lease obligations and to satisfy other miscellaneous obligations. The primary methods we use to meet those obligations are to post a corporate guarantee (i.e., self bond), provide a third-party surety bond or provide a letter of credit. As of December 31, 2014, we had $1,361.4 million of self bonding in place for our reclamation obligations. As of December 31, 2014, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of $1,122.5 million, of which $662.6 million was for post-mining reclamation, $126.4 million related to workers' compensation obligations, $103.8 million was for coal lease obligations and $229.7 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 are our secured credit agreement dated September 24, 2013 (the 2013 Credit Facility, as amended) and our accounts receivable securitization program.

Our failure to retain, or inability to acquire, surety bonds, bank guarantees 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 or lack of availability of letters of credit 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.

Regulatory agencies have the authority under certain circumstances following significant health and safety incidents to order a mine to be temporarily or permanently closed. In the event that such agencies ordered the closing of one of our mines, our production and sale of coal would be disrupted and we may be required to incur cash outlays to re-open the mine. Any of these actions could have a material adverse effect on our financial condition, results of operations and cash flows.

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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, which is driven by the estimated economic life of the mine and the applicable reclamation laws. These cash flows are 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, mine closing and post-closure 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.

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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, 2014, we leased a total of 73,310 acres from the federal government subject to those limitations. The limit could restrict our ability to lease additional U.S. federal lands.

Our planned mine development projects and acquisition activities may not result in significant additional reserves, and we may not have success developing additional mines. Most of our mining operations are conducted on properties owned or leased by us. Because we do not thoroughly verify title to most of our leased properties and mineral rights until we obtain a permit to mine the property, our right to mine some of our reserves may be materially adversely affected if defects in title or boundaries exist. In addition, in order to develop our reserves, we must also own the rights to the related surface property and receive various governmental permits. We cannot predict whether we will continue to receive the permits 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, causing production delays.

To the extent that our existing sources of liquidity are not sufficient to fund our planned mine development projects and reserve acquisition activities, we may require access to capital markets, which may not be available to us or, if available, may not be available on satisfactory terms. If we are unable to fund these activities, we may not be able to maintain or increase our existing production rates and we could be forced to change our business strategy, which could have a material adverse effect on our financial condition, results of operations and cash flows.

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, (1) have economic or business interests or goals that are inconsistent with, or opposed to, ours; (2) seek to block actions that the we believe are in our or the joint venture's best interests or (3) be unable or unwilling to fulfill their obligations under the joint venture or other agreements, such as contributing capital, each of which may adversely impact our results of operations or impair our ability to recover our investments. Where our joint ventures are jointly controlled or not managed by us, we may provide expertise and advice but have limited control over compliance with our operational standards. We also utilize contractors across our mining platform, and may be similarly limited in our ability to control their operational practices. Failure by non-controlled joint venture partners or contractors to adhere to operational standards that are equivalent to ours could unfavorably affect operating costs and productivity and adversely impact our results of operations and reputation.

As a result of our continuing efforts to reduce costs and optimize our organizational structure, we may undertake further restructuring plans that would require additional charges.

In 2014, we expanded our repositioning efforts to include voluntary and involuntary workforce reductions and office closures and initiated plans to consolidate certain shared services globally, and correspondingly incurred $15.7 million in aggregate charges during that period. As a result of our continuing review of our business, we may choose to further reduce our workforce and close additional offices in the future, which may result in further restructuring charges and cash expenditures and the consumption of management resources, any of which could cause our operating results to decline and may fail to yield the expected benefits.

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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, 2014, 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 Revolver 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.

Our financial performance could be adversely affected by our debt.

As of December 31, 2014, 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 on our access to, various forms of credit used in operating our business.

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If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets or seek additional capital to attempt to meet our debt service and other obligations. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations requiring us to seek to restructure or refinance our indebtedness. 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. In addition, under the 2013 Credit Facility, if we cannot meet our debt service obligations, the lenders could terminate their commitments to loan money, the lenders could foreclose against the assets securing their borrowings and we could be forced into bankruptcy or liquidation.

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 first lien 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.

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

We may not be able to fully utilize our deferred tax assets.

We are subject to income and other taxes in the U.S. and numerous foreign jurisdictions, most significantly Australia. As of December 31, 2014, we had gross deferred income tax assets and liabilities of $2,589.5 million and $1,428.9 million, respectively, as described further in Note 10. “Income Taxes” to the accompanying consolidated financial statements. At that date, we also had recorded a valuation allowance of $1,169.0 million, substantially comprised of a full valuation allowance against our net deferred tax asset positions in the U.S. and Australia driven by recent cumulative book losses, as determined by considering all sources of available income (including items classified as discontinued operations or recorded directly to "Accumulated other comprehensive loss"), which limited our ability to look to future taxable income in assessing the likelihood of realizing those assets.

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Although we may be able to utilize some or all of those deferred tax assets in the future if we have income of the appropriate character in those jurisdictions (subject to loss carryforward and tax credit expiry, in certain cases), there is no assurance that we will be able to do so. Further, we are presently unable to record tax benefits on future losses in the U.S. and Australia until such time as sufficient income is generated by our operations in those jurisdictions to support the realization of the related net deferred tax asset positions. Our results of operations, financial condition and cash flows may adversely be affected in future periods by these limitations.

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 us. 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 $839.1 million as of December 31, 2014, of which $57.2 million was classified as a current liability. Net pension liabilities were $162.7 million as of December 31, 2014, of which $1.7 million was classified a current liability.

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

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by government-backed lending institutions and development banks toward the financing of new overseas coal-fueled power plants and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities.

Global climate issues continue to attract public and scientific attention. Numerous reports, such as the Fourth (and, more recently, the Fifth) 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.

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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.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

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.

Item 2. Properties.

Coal Reserves

We had an estimated 7.6 billion tons of proven and probable coal reserves as of December 31, 2014. An estimated 6.6 billion tons of our attributable proven and probable coal reserves are in the U.S., with the remainder in Australia. Approximately 72% of our Australian proven and probable coal reserves, or 690 million tons, are metallurgical coal, comprised of approximately 215 million and 475 million tons of coking coal and low volatile pulverized coal injection (LV PCI) coals, respectively. The remainder of our Australian coal reserves consists of thermal coal. Approximately 53% of our reserves, or 4.0 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 32% of these reserves and lease property containing the remaining 68%. 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.

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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, 2014 (1)		
Operating Regions	Locations	Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	2,201	765	2,966
Powder River Basin	Wyoming	—	3,075	3,075
Southwest	Arizona and New Mexico	176	239	415
Colorado	Colorado	19	113	132
Total United States		2,396	4,192	6,588
New South Wales	Australia	—	339	339
Queensland	Australia	—	623	623
Total Australia		—	962	962
Total Proven and Probable Coal Reserves		2,396	5,154	7,550

(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. For some of our Australian coal reserves, the distance between points of observation is determined by a geostatistical study.

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.

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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, 2014 reflected a net reduction compared to the prior year of 715 million tons of coal reserves. The decrease was driven by adverse changes in economic factors, certain mine plan changes and the sale of non-strategic coal reserves, partially offset by the addition of 230 million tons of reserves due to additional drilling, certain mine plan changes and reserve acquisitions in 2014.

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. Our December 31, 2014 reserve estimates for the Powder River Basin region were audited by John T. Boyd Company, an independent mining and geological consulting firm, which included a review of the data, procedures and parameters employed by us in developing our Powder River Basin reserve estimates. The audit found that (1) the reserve estimates we prepared for the region were properly calculated in accordance with our stated procedures, (2) the procedures used by us are reasonable and comply with accepted industry standards and (3) our Powder River Basin reserve estimates, as a whole, provided a reasonable estimate of available controlled mineralization that can be expected to be legally and economically extractable at the time of determination. We plan to complete additional audits of our reserve estimates on a cycled basis for each of our major operating regions.

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, 2014, we leased 12,208 acres of federal land in Colorado, 640 acres in New Mexico and 52,200 acres in Wyoming, for a total of 65,048 nationwide subject to those limitations. An additional 8,262 acres in Wyoming are held under Lease by Application with 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 64,858 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 7.6 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 (in descending order by region) for the years ended December 31, 2014, 2013 and 2012, 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)

Geographic Region / Mining Complex	Production Year Ended December 31, 2014	2013	2012	Type of Coal	Sulfur Content of Assigned Reserves as of December 31, 2014 (1) <1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	As Received Btu per pound (2)
Midwest:								
Bear Run	8.4	8.2	7.9	T	5	29	232	11,500
Francisco Underground	3.1	2.9	2.8	T	—	—	31	11,500
Gateway (3)	2.5	2.8	2.8	T	—	—	75	10,900
Wild Boar	2.2	2.1	2.0	T	—	—	15	11,000
Wildcat Hills Underground	2.0	1.6	1.5	T	—	—	29	12,100
Cottage Grove	1.9	2.0	2.0	T	—	—	8	12,700
Somerville Central	1.9	2.6	2.3	T	—	—	21	11,500
Somerville North	1.5	1.5	1.2	T	—	—	1	11,200
Somerville South	1.3	1.5	1.4	T	—	—	4	11,100
Viking - Corning Pit (Closed in 2014)	0.1	1.1	1.3	T	—	—	—	NA
Willow Lake (Closed in 2012)	—	—	2.1	T	—	—	—	NA
Total	24.9	26.3	27.3		5	29	416	
Powder River Basin:								
North Antelope Rochelle	118.0	111.0	107.6	T	2,136	—	—	8,800
Rawhide	15.4	14.2	14.7	T	239	56	2	8,300
Caballo	8.0	9.0	16.9	T	603	35	4	8,400
Total	141.4	134.2	139.2		2,978	91	6	
Southwest:								
El Segundo	8.4	8.7	8.6	T	17	46	43	9,000
Kayenta	8.1	7.2	7.5	T	146	66	3	10,600
Lee Ranch	—	—	1.3	T	14	72	8	9,400
Total	16.5	15.9	17.4		177	184	54	
Colorado:								
Twentymile	6.7	7.2	8.0	T	4	—	42	11,200
Australia:								
Wilpinjong	14.4	13.3	12.2	T	—	169	—	11,200

Wambo (4)	6.5	6.9	6.6	T/P	142	—	—	12,200
Millennium	3.9	3.5	3.2	M/P	46	—	—	12,600
Coppabella	3.2	3.2	2.8	P	50	—	—	12,700
North Goonyella / Eaglefield	2.9	2.3	4.1	M	97	—	—	12,900
Moorvale	2.4	2.1	1.9	M/P	16	—	—	12,100
Metropolitan	2.5	1.5	1.8	M	28	—	—	12,600
Burton	1.9	2.0	1.2	M/T	10	—	—	12,700
Middlemount (5)	—	—	—	M/P	35	—	—	12,300
Total	37.7	34.8	33.8		424	169	—	
Total Continuing Operations	227.2	218.4	225.7		3,588	473	518	
Discontinued Operations	—	4.0	3.3		—	—	—	
Total Assigned	227.2	222.4	229.0		3,588	473	518	

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection Metallurgical

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ASSIGNED RESERVES [6]
AS OF DECEMBER 31, 2014

(Tons in Millions) Geographic Region/Mining Complex	Interest	Attributable Ownership Proven and Probable Reserves	Owned	Leased	Surface	Underground	100% Project Basis Proven and Probable Reserves	Owned	Leased	Surface	Underground
Midwest:											
Bear Run	100%	266	114	152	266	—	266	114	152	266	—
Gateway [3]	100%	75	73	2	—	75	75	73	2	—	75
Francisco Underground	100%	31	5	26	—	31	31	5	26	—	31
Wildcat Hills Underground	100%	29	13	16	—	29	29	13	16	—	29
Somerville Central	100%	21	18	3	21	—	21	18	3	21	—
Wild Boar	100%	15	12	3	15	—	15	12	3	15	—
Cottage Grove	100%	8	6	2	8	—	8	6	2	8	—
Somerville South	100%	4	3	1	4	—	4	3	1	4	—
Somerville North	100%	1	—	1	1	—	1	—	1	1	—
Total		450	244	206	315	135					
Powder River Basin:											
North Antelope Rochelle	100%	2,136	—	2,136	2,136	—	2,136	—	2,136	2,136	—
Caballo	100%	642	—	642	642	—	642	—	642	642	—
Rawhide	100%	297	—	297	297	—	297	—	297	297	—
Total		3,075	—	3,075	3,075	—					
Southwest:											
Kayenta	100%	215	—	215	215	—	215	—	215	215	—
El Segundo	100%	106	84	22	106	—	106	84	22	106	—
Lee Ranch	100%	94	92	2	94	—	94	92	2	94	—
Total		415	176	239	415	—					
Colorado:											
Twentymile	100%	46	12	34	—	46	46	12	34	—	46
Australia:											
Wilpinjong	100%	169	—	169	169	—	169	—	169	169	—
Wambo [4]	100%	142	—	142	55	87	142	—	142	55	87
	100%	97	—	97	—	97	97	—	97	—	97

North Goonyella / Eaglefield											
Coppabella	73.3%	50	—	50	50	—	68	—	68	68	—
Metropolitan	100%	28	—	28	—	28	28	—	28	—	28
Millennium	100%	46	—	46	46	—	46	—	46	46	—
Moorvale	73.3%	16	—	16	16	—	22	—	22	22	—
Burton	100%	10	—	10	10	—	10	—	10	10	—
Middlemount (5)	50.0%	35	—	35	35	—	70	—	70	70	—
Total		593	—	593	381	212					
Total Assigned		4,579	432	4,147	4,186	393					

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES (6)
AS OF DECEMBER 31, 2014
(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	112	1,966	2,078	963	1,115	112	1,966	2,078	963	1,115
Indiana	338	269	607	460	147	338	269	607	460	147
Kentucky (7)	—	281	281	134	147	—	281	281	134	147
Total	450	2,516	2,966	1,557	1,409					
Powder River Basin (Wyoming)	3,075	—	3,075	2,922	153	3,075	—	3,075	2,922	153
Southwest:										
Arizona	215	—	215	215	—	215	—	215	215	—
New Mexico	200	—	200	200	—	200	—	200	200	—
Total	415	—	415	415	—					
Colorado	46	86	132	86	46	46	86	132	86	46
Australia:										
New South Wales	339	—	339	271	68	339	—	339	271	68
Queensland	254	369	623	358	265	313	369	682	396	286
Total	593	369	962	629	333					
Total Proven and Probable	4,579	2,971	7,550	5,609	1,941					

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ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2014
(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	1,743	335	64	2,014	1,743	335	64	2,014
Indiana	328	279	441	166	328	279	441	166
Kentucky (7)	130	151	30	251	130	151	30	251
Total	2,201	765	535	2,431				
Powder River Basin (Wyoming)	—	3,075	3,075	—	—	3,075	3,075	—
Southwest:								
Arizona	—	215	215	—	—	215	215	—
New Mexico	176	24	200	—	176	24	200	—
Total	176	239	415	—				
Colorado	19	113	—	132	19	113	—	132
Australia:								
New South Wales	—	339	224	115	—	339	224	115
Queensland	—	623	413	210	—	682	—	682
Total	—	962	637	325				
Total Proven and Probable	2,396	5,154	4,662	2,888				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2014
(Tons in Millions)

		Attributable Ownership Sulfur Content [1]			100% Project Basis Sulfur Content [1]			
		<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	As
Coal Seam Location	Type of Coal	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Sulfur Dioxide per Million Btu	Received Btu per Pound [2]
Midwest:								
Illinois	T	—	—	2,078	—	—	2,078	10,300
Indiana	T	5	36	566	5	36	566	10,200
Kentucky [7]	T	—	—	281	—	—	281	10,900
Total		5	36	2,925				
Powder River Basin (Wyoming)	T	2,978	91	6	2,978	91	6	8,700
Southwest:								
Arizona	T	146	66	3	146	66	3	10,600
New Mexico	T	32	117	51	32	117	51	9,100
Total		178	183	54				
Colorado	T	84	—	48	84	—	48	10,700
Australia:								
New South Wales	T/M/P	170	169	—	170	169	—	11,800
Queensland	T/M/P	623	—	—	682	—	—	12,100
Total		793	169	—				
Total Proven and Probable		4,038	479	3,033				

T: Thermal
M: Metallurgical
P: Pulverized Coal Injection Metallurgical

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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) Includes coal reserves assigned to the planned Gateway North Mine, which is expected to replace production from the existing Gateway Mine as its reserves are exhausted in 2015

(4) Includes the Wambo Open-Cut Mine and the North Wambo Underground Mine. The North Wambo Underground Mine produces both thermal and low volatile pulverized coal injection metallurgical coal.

(5) Represents our 50.0% interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. Because that entity is accounted for as an unconsolidated equity affiliate, 2014, 2013 and 2012 tons produced by Middlemount have been excluded from the "Summary of Coal Production and Sulfur Content of Assigned Reserves" table. Middlemount produced 3.6 million tons of coal in 2014 (on a 100% basis).

(6) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2014. 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) Approximately 90% of our coal reserves in Kentucky are leased out to third parties.

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 and 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 achieve this goal by: setting clear expectations about safe work practices and training employees and contractors in those practices; holding ourselves and others accountable for a safe and healthy work environment; modeling and reinforcing behaviors that support safety and health best practices and our values; promoting processes to identify and manage risks, transparently reporting and investigating incidents and losses to develop effective corrective actions to prevent recurrence; and seeking ways to continually improve our safety and health standards and culture. We also believe personal accountability is key and expect every employee to commit to our safety goals and governing principles.

As part of our efforts, we collaborate with the Mine Safety and Health Administration (MSHA) and other government agencies to identify and test emerging safety technologies. 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 exploring, implementing or using leading technology to assist with proximity detection and fatigue monitoring.

Our "Safety a Way of Life Management System" has been designed to set clear and consistent expectations for safety and health across our business. It aligns to the National Mining Association's CORESafety® framework and encompasses three fundamental areas: leadership and organization, safety and health risk management, and assurance.

We use several metrics to measure our safety performance and primarily benchmark our performance based on our incidence rate, which is monitored through our safety tracking systems and represents the number of injuries that occurred for each 200,000 employee hours worked. 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 similar criteria.

Commensurate with MSHA reporting guidelines, our U.S. incidence rate presented below reflects activity from our full-time employees at our operating sites and, beginning in 2014, our temporary employees at those sites, and excludes contractors. Certain of our Australian mines are or have been operated by a contract miner; therefore, our Australia incidence rate includes activity from contractors. Both our U.S. and Australia incidence rates presented below exclude the impact of personnel from sales and administrative offices. Notwithstanding these reporting guidelines, we do continually monitor safety performance across our global workforce for internal management purposes, including that of our office and contractor personnel omitted from the metrics presented below.

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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,		
	2014	2013	2012
MSHA (U.S. coal mines)(1)	3.42	3.42	3.56
Peabody Energy Corporation Results:			
U.S.	1.31	1.00	1.28
Australia	1.79	2.79	2.50
Total Peabody Energy Corporation	1.54	1.87	1.87

(1) The MSHA All Incidence Rate for 2014 interim or full year periods was not yet published as of the filing of this report on February 25, 2015. The amount presented above corresponds with the 2013 All Incidence Rate because it is the most recently published measure.

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, 2014, 2013 and 2012, our U.S. violations per inspection day were 0.63, 0.57 and 0.76, respectively.

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 20, 2015, there were 1,230 holders of record of our common stock.

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

	Share Price		Dividends
	High	Low	Paid
2014			
First Quarter	$19.94	$15.18	$0.085
Second Quarter	19.63	15.79	0.085
Third Quarter	16.71	11.88	0.085
Fourth Quarter	12.41	7.23	0.085
2013			
First Quarter	$27.74	$20.07	$0.085
Second Quarter	21.85	14.35	0.085
Third Quarter	19.27	14.34	0.085
Fourth Quarter	21.28	16.78	0.085

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Dividend Policy

We have declared and paid quarterly dividends since our initial public offering in 2001. On January 27, 2015, our Board of Directors declared a dividend of $0.0025 per share of Common Stock, payable on February 26, 2015, to stockholders of record on February 6, 2015. Our Board of Directors will continue to evaluate our dividend rate on a quarterly basis and the declaration and payment of dividends in the future and the amount of those dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt covenants and other factors that our Board of Directors may deem relevant to such evaluations. 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, 2014, 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, 2014, 2013 or 2012.

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.

Limitations on share repurchases 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 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.

Purchases of Equity Securities

The following table summarizes all share purchases for the three months ended December 31, 2014:

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, 2014	6,254	$11.16	—	$700.4
November 1 through November 30, 2014	2,986	11.49	—	700.4
December 1 through December 31, 2014	2,211	7.72	—	700.4
Total	11,451	$10.58	—	

[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 III, 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.

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Item 6. Selected Financial Data.

This item presents selected financial and other data about us for the most recent five fiscal years.

The table that follows and the discussion of our results of operations in 2014, 2013 and 2012 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 (Loss) 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 definition of Adjusted EBITDA to also exclude the impact of changes in deferred tax asset valuation allowance related to equity affiliates because we believe that doing so is useful in comparing our results between periods. Our Adjusted (Loss) Income from Continuing Operations and Adjusted Diluted EPS measures were not modified in this manner in order to consistently include the effects of changes in deferred tax asset valuation allowances related to our equity affiliates and those of our consolidated entities.

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 changes in deferred tax asset valuation allowance 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 (Loss) 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, 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, 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 (Loss) 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 (Loss) 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).

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, 2014, 2013, 2012, 2011 and 2010 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.

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	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	$6,792.2	$7,013.7	$8,077.5	$7,895.9	$6,668.2
Costs and expenses	6,927.3	7,338.5	7,905.0	6,300.2	5,317.1
Operating (loss) profit	(135.1)	(324.8)	172.5	1,595.7	1,351.1
Interest expense, net	412.8	409.5	381.1	219.7	212.4
(Loss) income from continuing operations before income taxes	(547.9)	(734.3)	(208.6)	1,376.0	1,138.7
Income tax provision (benefit)	201.2	(448.3)	262.3	363.2	313.7
(Loss) income from continuing operations, net of income taxes	(749.1)	(286.0)	(470.9)	1,012.8	825.0
Loss from discontinued operations, net of income taxes	(28.2)	(226.6)	(104.2)	(66.5)	(22.8)
Net (loss) income	(777.3)	(512.6)	(575.1)	946.3	802.2
Less: Net income (loss) attributable to noncontrolling interests	9.7	12.3	10.6	(11.4)	28.2
Net (loss) income attributable to common stockholders	$(787.0)	$(524.9)	$(585.7)	$957.7	$774.0
Basic EPS - (Loss) income from continuing operations	$(2.83)	$(1.12)	$(1.80)	$3.78	$2.96
Diluted EPS - (Loss) income from continuing operations	$(2.83)	$(1.12)	$(1.80)	$3.77	$2.92
Weighted average shares used in calculating basic EPS	268.1	267.1	268.0	269.1	267.0
Weighted average shares used in calculating diluted EPS	268.1	267.1	268.0	270.3	269.9
Dividends declared per share	$0.340	$0.340	$0.340	$0.340	$0.295
Other Data					
Tons sold	249.8	251.7	248.5	249.4	243.1
Net cash provided by (used in) continuing operations:					
Operating activities	$441.0	$780.1	$1,599.8	$1,652.1	$1,104.5
Investing activities	(314.5)	(514.2)	(1,070.1)	(3,737.2)	(692.7)
Financing activities	(168.1)	(321.5)	(663.3)	1,678.5	(77.1)
Adjusted EBITDA	814.0	1,047.2	1,836.5	2,122.6	1,826.5
Adjusted (Loss) Income from Continuing Operations	(597.4)	104.5	238.7	1,011.9	872.9
Adjusted Diluted EPS	$(2.27)	$0.34	$0.84	$3.77	$3.10
Balance Sheet Data (at period end)					
Total assets	$13,191.1	$14,133.4	$15,809.0	$16,733.0	$11,363.1
Total long-term debt (including capital leases)	5,986.8	6,002.4	6,252.9	6,657.5	2,750.0
Total stockholders’ equity	2,726.5	3,947.9	4,938.8	5,515.8	4,689.3

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Adjusted EBITDA is calculated as follows:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
		(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$(749.1)	$(286.0)	$(470.9)	$1,012.8	$825.0
Depreciation, depletion and amortization	655.7	740.3	663.4	474.3	429.5
Asset retirement obligation expenses	81.0	66.5	67.0	52.6	45.9
Asset impairment and mine closure costs	154.4	528.3	929.0	—	—
Settlement charges related to the Patriot bankruptcy reorganization	—	30.6	—	—	—
Change in deferred tax asset valuation allowance related to equity affiliates	52.3	—	—	—	—
Amortization of basis difference related to equity affiliates	5.7	6.3	4.6	—	—
Interest expense, net	412.8	409.5	381.1	219.7	212.4
Income tax provision (benefit)	201.2	(448.3)	262.3	363.2	313.7
Adjusted EBITDA	$814.0	$1,047.2	$1,836.5	$2,122.6	$1,826.5

Adjusted (Loss) Income from Continuing Operations is calculated as follows:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(Dollars in millions)				
(Loss) income from continuing operations, net of income taxes	$(749.1)	$(286.0)	$(470.9)	$1,012.8	$825.0
Asset impairment and mine closure costs	154.4	528.3	929.0	—	—
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)	—	—
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	(2.7)	(44.3)	7.9	(0.9)	47.9
Adjusted (Loss) Income from Continuing Operations	$(597.4)	$104.5	$238.7	$1,011.9	$872.9

Adjusted Diluted EPS is calculated as follows:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Diluted EPS - (Loss) income from continuing operations	$(2.83)	$(1.12)	$(1.80)	$3.77	$2.92
Asset impairment and mine closure costs, net of income taxes	0.57	1.56	2.61	—	—
Settlement charges related to the Patriot bankruptcy reorganization, net of income taxes	—	0.07	—	—	—
Remeasurement (benefit) expense related to foreign income tax accounts	(0.01)	(0.17)	0.03	—	0.18
Adjusted Diluted EPS	$(2.27)	$0.34	$0.84	$3.77	$3.10

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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. As of December 31, 2014, we owned interests in 26 active coal mining operations located in the United States (U.S.) and Australia. We have a majority interest in 25 of those mining operations and a 50% equity interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, 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 Australia, China, Germany, India, Indonesia, Singapore, the United Kingdom and the U.S. (listed alphabetically).

In 2014, we produced and sold 227.2 million and 249.8 million tons of coal, respectively, from continuing operations. During that period, 75% of our total sales (by volume) were to U.S. electricity generators, 23% were to customers outside the U.S. and 2% were to the U.S. industrial sector, with approximately 83% of our worldwide sales (by volume) delivered under long-term contracts.

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 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 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 as seaborne exports.

Our Trading and Brokerage segment engages in the direct and brokered trading of coal and freight-related contracts through the trading and business offices mentioned above. Coal brokering is conducted both as principal and agent in support of various coal production-related activities that may involve coal produced from our mines, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. Our Trading and Brokerage segment also provides transportation-related services, which involves both financial derivative contracts and physical contracts. Collectively, coal and freight-related hedging activities include both economic hedging and cash flow hedging in support of our coal trading strategy, and cash flow hedging in support of sales from our mining operations.

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

To maximize the utilization of our coal assets and land holdings, 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 future production levels in response to changes in market demand.

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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 (Loss) 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 definition of Adjusted EBITDA to also exclude the impact of changes in deferred tax asset valuation allowance related to equity affiliates because we believe that doing so is useful in comparing our results between periods. Our Adjusted (Loss) Income from Continuing Operations and Adjusted Diluted EPS measures were not modified in this manner in order to consistently include the effects of changes in deferred tax asset valuation allowances related to our equity affiliates and those of our consolidated entities. Also beginning in 2014, we modified our expense allocation practices to exclude restructuring and pension settlement charges from our Australian Mining, Western U.S. Mining, Midwestern U.S. Mining and Trading and Brokerage segment results because we believe such items to not reflect the core operating performance of those segments. Accordingly, such charges are now entirely reflected in our Corporate and Other segment. Segment results from prior periods have been reclassified to conform to the 2014 presentation.

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 changes in deferred tax asset valuation allowance 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 (Loss) 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 (Loss) 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 (Loss) 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, 2014 Compared to Year Ended December 31, 2013

Summary

Conditions in the coal market segments that we serve were varied in 2014, characterized by (1) continued pricing declines in international seaborne markets based on an abundance of supply and slowing demand growth, and (2) stable demand in the U.S. in spite of certain transportation- and weather-related headwinds.

In global metallurgical coal market segments, demand remained relatively flat during the year ended December 31, 2014 compared to the prior year and failed to provide a catalyst for a pricing rebound from 2013. Worldwide steel production increased only slightly during that period (1.2%) according to data recently published by the World Steel Association (WSA), driven by marginal growth in production out of Asia, the U.S. and the European Union. Demand for international seaborne thermal coal declined modestly in 2014 compared to 2013, as growth in imports into India only partially offset a decline in Chinese imports compared to the prior year.

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Overall, sluggish demand and the impact of continued growth in supply drove a further decline in international seaborne coal prices in 2014. Benchmark pricing for seaborne premium high quality hard coking coal (HQHCC), premium low volatile pulverized coal injections products (LV PCI) and thermal coal originating from Newcastle, Australia (NEWC) for 2014 and 2013 were as follows (on a per tonne basis):

Contract Commencement Month:	HQHCC 2014	HQHCC 2013	Increase (Decrease) to Prices %	LV PCI 2014	LV PCI 2013	Increase (Decrease) to Prices %	NEWC 2014	NEWC 2013	Increase (Decrease) to Prices %
January	$143	$165	(13)%	$116	$124	(6)%	$87	$91	(4)%
April	$120	$172	(30)%	$100	$141	(29)%	$82	$95	(14)%
July	$120	$145	(17)%	$100	$116	(14)%	$76	$90	(16)%
October	$119	$152	(22)%	$99	$121	(18)%	$74	$86	(14)%

In the U.S., electricity generation from coal was stable during the year ended December 31, 2014 compared to the prior year and maintained a share of 38.9% of total electricity generation during that period according to the U.S. Energy Information Administration (EIA). U.S. electricity generation from coal benefited during 2014 compared to the prior year from higher natural gas prices and colder first quarter weather, which offset the effects of poor rail performance and mild weather in the second half of the year. Overall, our total U.S. volumes shipped increased in the year ended December 31, 2014, as customers continued to replenish depleted stockpile inventories in the second half of the year even as electricity demand fell due to weather conditions.

Our revenues decreased during the year ended December, 2014 compared to the prior year ($221.5 million) due to lower overall realized pricing from our mining platform ($602.6 million), partially offset by an overall increase in tons sold from our mining platform.

In order to mitigate the impact of lower coal pricing, we continued to focus on driving operational efficiencies, optimizing production across our mining platform and controlling expenses at all levels of the organization in 2014. Overall, Adjusted EBITDA decreased during the year ended December 31, 2014 compared to the prior year ($233.2 million). Net results attributable to common stockholders also decreased in the year ended December 31, 2014 compared to the prior year ($262.1 million). In addition to lower Adjusted EBITDA, our 2014 results also reflected an adverse impact from income taxes, a change in valuation allowance related to an equity affiliate and higher asset retirement obligation expenses, partially offset by lower asset impairment charges, a decrease in depreciation, depletion and amortization, improved results from discontinued operations and the impact of a 2013 settlement charge related to the bankruptcy reorganization of Patriot Coal Corporation, which are discussed further in the sections that follow.

As of December 31, 2014, our available liquidity was approximately $2.1 billion, in line with the prior year. 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, 2014 and 2013:

	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase (Decrease) to Tons Sold: Tons	Increase (Decrease) to Tons Sold: %
	(Tons in millions)			
Australian Mining	38.2	34.9	3.3	9.5%
Western U.S. Mining	166.4	158.8	7.6	4.8%
Midwestern U.S. Mining	25.0	26.3	(1.3)	(4.9)%
Total tons sold from mining segments	229.6	220.0	9.6	4.4%
Trading and Brokerage	20.2	31.7	(11.5)	(36.3)%
Total tons sold	249.8	251.7	(1.9)	(0.8)%

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Revenues

The following table presents revenues by operating segment for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2014	2013	$	%
	(Dollars in millions)			
Australian Mining	$2,671.8	$2,904.6	$(232.8)	(8.0)%
Western U.S. Mining	2,825.7	2,669.6	156.1	5.8%
Midwestern U.S. Mining	1,198.1	1,335.5	(137.4)	(10.3)%
Trading and Brokerage	58.4	66.0	(7.6)	(11.5)%
Corporate and Other	38.2	38.0	0.2	0.5%
Total revenues	$6,792.2	$7,013.7	$(221.5)	(3.2)%

Australia Mining. The decrease in our Australian Mining segment revenues for the year ended December 31, 2014 compared to the prior year was primarily driven by lower realized coal prices ($577.1 million), partially offset by the favorable impact of changes in volume and mix ($344.3 million). The increase in production volumes reflected the 2014 ramp-ups of longwall top coal caving technology (LTCC) at our North Goonyella Mine and a new longwall at our Metropolitan Mine, in addition to the effect of prior year roof stability issues at those sites and a 2013 industrial action at the Metropolitan Mine. Those positive volume drivers were partially offset by lower production from our Eaglefield Mine due to the exhaustion of coal reserves at that site and extended overall longwall move downtimes at our North Wambo Underground Mine. Metallurgical coal sales from the segment totaled 17.6 million and 15.9 million tons in 2014 and 2013, respectively, while seaborne thermal coal sales totaled 13.0 million and 11.4 million tons during those periods, respectively.

Western U.S. Mining. The increase in Western U.S. Mining segment revenues for the year ended December 31, 2014 compared to the prior year was largely driven by a 4.8% rise in sales volumes ($101.5 million). That growth reflected the impacts on customer demand of higher natural gas prices, lower customer coal stockpile levels and an increase in heating-degree days during the winter months, tempered by the adverse effect of poor rail performance in the U.S. Powder River Basin and lower cooling-degree days in the summer months. The segment also benefited in 2014 from higher realized coal prices ($54.6 million) due to $33.5 million of additional contract revenue from finalized pricing under one of our sales agreements and favorable customer mix.

Midwestern U.S. Mining. Revenues from our Midwestern U.S. Mining segment were adversely impacted during the year ended December 31, 2014 compared to the prior year by lower realized coal prices ($80.1 million) due to the effect of contract price re-openers and the renewal of sales contracts at less favorable prices. The decline in revenues was also partially attributed to an unfavorable volume and mix variance ($57.3 million), which reflected the first quarter 2014 exhaustion of coal reserves at our Viking-Corning Pit Mine.

Trading and Brokerage. The decline in Trading and Brokerage segment revenues for the year ended December 31, 2014 compared to the prior year reflected lower pass-through charges for transportation costs due to a decrease in physical volumes, partially offset by an improvement in net realized contract margins.

Segment Adjusted EBITDA

The following table presents Segment Adjusted EBITDA for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2014	2013	$	%
	(Dollars in millions)			
Australian Mining	$74.4	$316.6	$(242.2)	(76.5)%
Western U.S. Mining	770.4	698.3	72.1	10.3%
Midwestern U.S. Mining	301.4	428.3	(126.9)	(29.6)%
Trading and Brokerage	14.9	(19.9)	34.8	(174.9)%
Total Segment Adjusted EBITDA	$1,161.1	$1,423.3	$(262.2)	(18.4)%

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Australian Mining. Adjusted EBITDA from our Australian Mining segment was adversely affected during the year ended December 31, 2014 compared to the prior year by lower realized metallurgical and thermal coal pricing, net of sales-related costs ($532.1 million) and inflationary cost escalations ($70.9 million). Those factors were partially offset by the effect of cost containment programs deployed in 2014 ($163.4 million), improved longwall performance from our underground mines due to the factors noted above ($150.1 million) and higher productivity and lower costs at our Australian surface mines ($35.3 million) driven by owner-operator conversions at certain sites that were completed in the second quarter of 2013 and the third quarter of 2014. While tons sold increased by 9.5% in 2014 compared to the prior year, the resulting benefits were largely offset by lower weighted-average margins experienced across the platform.

Western U.S. Mining. The increase in Western U.S. Mining segment Adjusted EBITDA during the year ended December 31, 2014 compared to the prior year reflected a favorable volume and mix variance ($59.7 million) and higher realized pricing, net of sales-related costs ($45.3 million) due to $27.1 million of additional contract revenue, net of sales-related costs, recognized from finalized pricing under one of our sales agreements and favorable customer mix. Those positive factors were partially offset by the timing of expenditures for repairs and maintenance and higher overall longwall move downtimes at our Twentymile Mine.

Midwestern U.S. Mining. The decrease in Midwestern U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2014 compared to the prior year was driven by lower realized coal prices, net of sales-related costs ($76.4 million), a decline in volumes ($19.6 million) and costs associated with higher overburden ratios at certain of our surface mines due to mine sequencing ($18.1 million).

Trading and Brokerage. The increase in Trading and Brokerage segment Adjusted EBITDA during the year ended December 31, 2014 compared to the prior year reflected improved net contract margins and the effect of expenses associated with a third-party contract miner that were incurred in the prior year. Trading and Brokerage results also benefited in 2014 compared to the prior year from a $12.8 million decline in charges associated with litigation and arbitration matters. Refer to Note 24. "Commitments and Contingencies" to the accompanying consolidated financial statements for additional information surrounding the Eagle Mining, LLC (Eagle Mining) arbitration and the Gulf Power Company (Gulf Power) litigation, for which matters we recorded aggregate charges of $15.6 million and $28.4 million during the years ended December 31, 2014 and 2013, respectively.

Loss From Continuing Operations Before Income Taxes

The following table presents loss from continuing operations before income taxes for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Income	
	2014	2013	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$1,161.1	$1,423.3	$(262.2)	(18.4)%
Corporate and Other Adjusted EBITDA	(347.1)	(376.1)	29.0	7.7%
Depreciation, depletion and amortization	(655.7)	(740.3)	84.6	11.4%
Asset retirement obligation expenses	(81.0)	(66.5)	(14.5)	(21.8)%
Asset impairment	(154.4)	(528.3)	373.9	70.8%
Settlement charges related to the Patriot bankruptcy reorganization	—	(30.6)	30.6	100.0%
Change in deferred tax asset valuation allowance related to equity affiliates	(52.3)	—	(52.3)	n.m.
Amortization of basis difference related to equity affiliates	(5.7)	(6.3)	0.6	9.5%
Interest expense	(428.2)	(425.2)	(3.0)	(0.7)%
Interest income	15.4	15.7	(0.3)	(1.9)%
Loss from continuing operations before income taxes	$(547.9)	$(734.3)	$186.4	25.4%

Results from continuing operations before income taxes for the year ended December 31, 2014 improved compared to the prior year. The decrease in Segment Adjusted EBITDA discussed above, an adverse change in valuation allowance related to the Middlemount equity affiliate and higher asset retirement obligation expenses were more than offset by lower asset impairment charges and depreciation, depletion and amortization, the effect of a 2013 settlement charge related to the bankruptcy reorganization of Patriot Coal Corporation and an improvement in Corporate and Other Adjusted EBITDA.

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Corporate and Other Adjusted EBITDA. The following table presents a summary of the components of Corporate and Other Adjusted EBITDA for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Income	
	2014	2013	$	%
	(Dollars in millions)			
Resource management activities [1]	$30.9	$49.5	$(18.6)	(37.6)%
Selling and administrative expenses	(227.1)	(244.2)	17.1	7.0%
Restructuring and pension settlement costs	(26.0)	(11.9)	(14.1)	(118.5)%
Other items, net [2]	(124.9)	(169.5)	44.6	26.3%
Corporate and Other Adjusted EBITDA	$(347.1)	$(376.1)	$29.0	7.7%

(1) Includes gains (losses) on certain surplus coal reserve and surface land sales and property management costs and revenues.

(2) Includes results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and amortization of basis difference), costs associated with past mining activities, certain coal royalty expenses, gains (losses) on certain asset disposals and expenses related to our other commercial activities.

Resource management earnings decreased during the year ended December 31, 2014 compared to the prior year due to reduced gains from the disposal of non-core assets. That decline was driven by the effect of the 2013 sale of non-strategic coal reserves and surface lands located in Kentucky, partially offset by the 2014 sale of non-strategic coal reserves located in Kentucky and surplus lands in the Midwestern U.S. The reduction in selling and administrative expenses during the year ended December 31, 2014 compared to the prior year largely reflected the impact of our ongoing cost containment efforts. The increase in restructuring and pension settlement costs during the year ended December 31, 2014 compared to the prior year was driven by the effect of a lump sum payout option offered to certain qualifying participants of one of our plans in the fourth quarter of 2014. That unfavorable change also reflected an increase in voluntary and involuntary workforce reduction activity in 2014 related to our ongoing repositioning efforts to appropriately align our cost structure relative to prevailing global coal industry conditions.

The improvement in "Other items, net" during the year ended December 31, 2014 compared to the prior year was driven by:

- Lower costs associated with past mining activities ($13.0 million) driven by the elimination of postretirement healthcare expenses for which the liabilities were settled with Patriot Coal Corporation and certain of its wholly-owned subsidiaries (Patriot) and the United Mine Workers of America (UMWA) pursuant to the definitive settlement agreement that became effective on December 18, 2013;
- A decrease in pension and other postretirement benefit costs primarily due to an increase in discount rates as of the beginning of each fiscal period ($12.2 million);
- The impact of charges of $8.0 million and $20.0 million recorded in 2014 and 2013, respectively, for environmental clean-up related costs associated with Gold Fields Mining, LLC, a dormant, non-coal producting entity that was previously managed and owned by our predecessor owner and transferred to us in a 1997 spin-off; and
- The third quarter 2014 receipt of $9.4 million of insurance proceeds related to equipment damage losses incurred in a previous period.

Those positive factors were partially offset by an unfavorable change in results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and amortization of basis difference) driven by lower coal pricing, as tempered by the benefit of productivity advancements resulting from the third quarter 2013 conversion of the Middlemount Mine to owner-operator status ($15.7 million).

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Depreciation, Depletion and Amortization. The following table presents a summary of depreciation, depletion and amortization expense by segment for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Income	
	2014	2013	$	%
	(Dollars in millions)			
Australian Mining	$(340.4)	$(406.4)	$66.0	16.2%
Western U.S. Mining	(213.0)	(220.2)	7.2	3.3%
Midwestern U.S. Mining	(69.6)	(80.4)	10.8	13.4%
Trading and Brokerage	(1.2)	(0.7)	(0.5)	(71.4)%
Corporate and Other	(31.5)	(32.6)	1.1	3.4%
Total	$(655.7)	$(740.3)	$84.6	11.4%

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, 2014 and 2013:

	Year Ended December 31,	
	2014	2013
Australian Mining	$3.88	$5.03
Western U.S. Mining	0.73	0.81
Midwestern U.S. Mining	0.46	0.66

The decrease in depreciation, depletion and amortization expense during the year ended December 31, 2014 compared to the prior year was predominantly driven by lower expense from our Australian Mining segment. That decrease reflected lower depletion rates at certain sites with historically higher rates due to an increase in estimated proven and probable reserves at those sites and a reduction in the asset base of one of our surface mines from asset impairment charges recognized in the fourth quarter of 2013. Those drivers were partially offset by the effect of a year-over-year increase in tons sold.

The decline in expense from our Midwestern U.S. Mining during the year ended December 31, 2014 compared to the prior year reflected a favorable shift in production mix toward lower depletion rate coal reserves and lower tons sold.

Expense from our Western U.S. Mining segment also decreased during the year ended December 31, 2014 compared to the prior year due to the effect of a shift in production mix towards lower depletion rate coal reserve locations. That effect more than offset the increase in tons sold during the year ended December 31, 2014 compared to the prior year.

Asset Retirement Obligation Expenses. In December 2014, we recognized an asset retirement obligation liability of $22.2 million due to the nonperformance of a contract miner at a coal reserve property in the Eastern U.S. Because mining operations have ceased at that operation, a corresponding charge for the full amount of the liability was recorded to “Asset retirement obligation expenses” in the consolidated statement of operations for the year then ended. The year-over-year increase in 2014 compared to the prior year also reflected higher amortization that results from an overall increase in tons sold across our mining segments, partially offset by lower expense for ongoing reclamation in certain U.S. regions due to a reduction in affected acreage.

Asset Impairment. We recognized $154.4 million and $528.3 million in aggregate asset impairment charges during the years ended December 31, 2014 and 2013, 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.

Settlement Charges Related to the Patriot Bankruptcy Reorganization. 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 Reorganization of Patriot Coal Corporation" to the accompanying consolidated financial statements for additional information surrounding the related matters.

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Change in Deferred Tax Asset Valuation Allowance Related to Equity Affiliates. During the year ended December 31, 2014, we recognized a $52.3 million charge for our pro-rata share of a valuation allowance on Middlemount's Australian net deferred tax assets. Based on available sources of taxable income, we determined that the net deferred tax assets are no longer considered more likely than not of being realized. That conclusion was driven by a history of operating losses, as sustained weakness in seaborne metallurgical coal prices have more than offset a successful owner-operator conversion completed in 2013 and an ongoing series of operational efficiency initiatives conducted at the site that have improved the mine's cost structure.

Interest Expense. Interest expense for year ended December 31, 2014 included an aggregate charge of $12.6 million related to the Sumiseki Materials Co. Ltd. (Sumiseki) litigation and Eagle Mining arbitration. Interest expense for the year ended December 31, 2014 also included $1.6 million of professional fees associated with the 2014 consent solicitation and related supplemental indenture for our Convertible Junior Subordinated Debentures due December 2066 (the Debentures). Interest expense for year ended December 31, 2013 included an aggregate early debt extinguishment charge of $16.9 million associated with the prior year execution of our secured credit agreement dated September 24, 2013 (as amended, the 2013 Credit Facility) and prior year voluntary debt prepayments and repurchases. Interest expense for the year ended December 31, 2013 also included a $6.9 million charge for pre-judgment interest related to the Gulf Power litigation. Changes in interest expense during the year ended December 31, 2014 compared to the prior year also reflected the unfavorable effect of higher interest rates associated with our term loan borrowings, partially offset by the beneficial impact of lower overall debt balances.

Refer to Note 24. "Commitments and Contingencies" to the accompanying consolidated financial statements for additional information surrounding the foregoing litigation and arbitration matters.

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, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Income	
	2014	2013	$	%
	(Dollars in millions)			
Loss from continuing operations before income taxes	$(547.9)	$(734.3)	$186.4	25.4%
Income tax provision (benefit)	201.2	(448.3)	(649.5)	144.9%
Loss from continuing operations, net of income taxes	$(749.1)	$(286.0)	$(463.1)	(161.9)%

Results from continuing operations, net of income taxes, declined for the year ended December 31, 2014 compared to the prior year due to the effect of income taxes, partially offset by improved before-tax earnings.

Income Tax Provision (Benefit). The year-over-year negative effect of income taxes was driven by:

- An increase in valuation allowance on certain U.S. and Australian deferred tax assets that was recognized during the year ended December 31, 2014 driven by recent cumulative book losses, as determined by considering all sources of available taxable income (including items classified as discontinued operations or recorded directly to "Accumulated other comprehensive loss"), which limited our ability to look to future taxable income in assessing the realizability of those assets ($569.4 million);
- The aggregate impact of the write-off of a net deferred tax asset in 2014 due to the repeal of the Australian Minerals and Resource Rent Tax (MRRT) compared with MRRT royalty allowance benefits recognized in the prior year ($78.3 million);
- The effect of improved before-tax earnings, including the 2013 income tax effects of asset impairments and charges associated with claims and litigation related to the Patriot bankruptcy reorganization ($47.8 million); and
- Lower remeasurement benefits related to foreign income tax accounts ($41.6 million).

Those factors were partially offset in the year ended December 31, 2014 by a decrease in net unrecognized tax benefits, interest and penalties, primarily due to amended returns filed and the finalization of audits by the Australian Tax Office for certain tax years ($99.4 million).

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Adjusted (Loss) Income From Continuing Operations

The following table presents Adjusted (Loss) Income from Continuing Operations for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Income	
	2014	2013	$	%
	(Dollars in millions)			
Loss from continuing operations, net of income taxes	$(749.1)	$(286.0)	$(463.1)	(161.9)%
Asset impairment	154.4	528.3	(373.9)	(70.8)%
Settlement charges related to the Patriot bankruptcy reorganization	—	30.6	(30.6)	(100.0)%
Income tax benefit related to asset impairment	—	(112.8)	112.8	100.0 %
Income tax benefit related to the settlement charges related to the Patriot bankruptcy reorganization	—	(11.3)	11.3	(100.0)%
Remeasurement benefit related to foreign income tax accounts	(2.7)	(44.3)	41.6	(93.9)%
Adjusted (Loss) Income from Continuing Operations	$(597.4)	$104.5	$(701.9)	(671.7)%

Adjusted (Loss) Income from Continuing Operations changed unfavorably for the year ended December 31, 2014 compared to the prior year. The decline in results reflected the adverse effect of income taxes, lower Adjusted EBITDA, an adverse change in valuation allowance related to the Middlemount Mine equity affiliate and higher asset retirement obligation expenses, partially offset by lower depreciation, depletion and amortization, 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, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to Income	
	2014	2013	$	%
	(Dollars in millions)			
Loss from continuing operations, net of income taxes	$(749.1)	$(286.0)	$(463.1)	(161.9)%
Loss from discontinued operations, net of income taxes	(28.2)	(226.6)	198.4	87.6 %
Net loss	(777.3)	(512.6)	(264.7)	(51.6)%
Net income attributable to noncontrolling interests	9.7	12.3	2.6	21.1 %
Net loss attributable to common stockholders	$(787.0)	$(524.9)	$(262.1)	(49.9)%

Net results attributable to common stockholders declined during the year ended December 31, 2014 compared to the prior year largely due to the unfavorable change in results from continuing operations, net of income taxes, discussed above, partially offset by the favorable impact of changes in results from discontinued operations.

Loss from Discontinued Operations, Net of Income Taxes. Results from discontinued operations improved during the year ended December 31, 2014 compared to the prior year, mainly driven by the following:

- Changes in results from the Wilkie Creek Mine that was closed in the fourth quarter of 2013 ($157.6 million), which reflected after-tax asset impairment and mine closure costs of $117.2 million recognized in 2013, the effect of 2013 operating losses and a net gain of $4.6 million recognized in 2014 related to the termination of a sale and purchase agreement with a potential buyer of that mine due to the inability of that buyer to meet the necessary conditions for closing; and
- Prior year after-tax charges of $61.8 million associated with the settlement of claims and litigation related to the Patriot bankruptcy reorganization pursuant to the definitive settlement agreement that we reached with Patriot and the UMWA effective December 18, 2013; partially offset by
- A charge of $34.1 million recorded in 2014 related to an adverse change in the fair value of the credit support we have provided to Patriot in connection with the settlement agreement due to a credit downgrade of Patriot issued by one of the major credit rating agencies in the fourth quarter of 2014.

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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 Reorganization of Patriot Coal Corporation" to the accompanying consolidated financial statements, respectively.

Diluted EPS

The following table presents diluted EPS for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2014	2013	$	%
Diluted EPS attributable to common stockholders:				
Loss from continuing operations	$(2.83)	$(1.12)	$(1.71)	(152.7)%
Loss from discontinued operations	(0.11)	(0.85)	0.74	87.1 %
Net loss	$(2.94)	$(1.97)	$(0.97)	(49.2)%

Diluted EPS declined in the year ended December 31, 2014 compared to the prior year commensurate with the unfavorable change in results from continuing operations between those periods, partially offset by improved results from discontinued operations.

Adjusted Diluted EPS

The following table presents Adjusted Diluted EPS for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase (Decrease) to EPS	
	2014	2013	$	%
Adjusted Diluted EPS Reconciliation:				
Loss from continuing operations	$(2.83)	$(1.12)	$(1.71)	(152.7)%
Asset impairment, net of income taxes	0.57	1.56	(0.99)	(63.5)%
Settlement charges related to the Patriot bankruptcy reorganization, net of income taxes	—	0.07	(0.07)	(100.0)%
Remeasurement benefit related to foreign income tax accounts	(0.01)	(0.17)	0.16	(94.1)%
Adjusted Diluted EPS	$(2.27)	$0.34	$(2.61)	(767.6)%

Adjusted Diluted EPS for the year ended December 31, 2014 decreased compared to the prior year commensurate with the decline in Adjusted (Loss) Income from Continuing Operations during that period.

Other

The net fair value of our diesel fuel cash flow hedge contract portfolio decreased from a net asset of $6.4 million at December 31, 2013 to a net liability of $167.1 million at December 31, 2014 primarily due to the decline in forward diesel prices during that period. The 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.

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 impacted our results for the period.

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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 2012 according to the WSA. Similarly, international seaborne thermal coal demand increased in the year ended December 31, 2013 compared to 2012, led by imports into China, India, Japan and Germany. Nonetheless, growth in seaborne coal market supply outpaced the increase in demand in 2013, which constrained international coal prices. Quarterly benchmark pricing for seaborne HQHCC, LV PCI and 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 2012 according to the EIA. U.S. electric power generation from coal benefited in 2013 compared to 2012 from gas-to-coal switching due to higher natural gas prices and higher heating-degree days during winter months, partially offset by lower cooling-degree days. 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.

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.

Overall, Adjusted EBITDA decreased during the year ended December 31, 2013 compared to the prior year ($789.3 million), as lower revenues were partially offset by the benefits associated with owner-operator conversions completed at several of our Australian mines during the second quarter of 2013, productivity improvements realized at certain Australian operations acquired in late 2011 from optimization and remediation efforts completed in 2012 and the reduced use of contractors, temporary labor and overtime across the platform. 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, which are discussed further in the sections that follow.

Tons Sold

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

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase (Decrease) to Tons Sold Tons	Increase (Decrease) to Tons Sold %
	(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)%
Total tons sold from mining segments	220.0	225.6	(5.6)	(2.5)%
Trading and Brokerage	31.7	22.9	8.8	38.4 %
Total tons sold	251.7	248.5	3.2	1.3 %

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Revenues

The following table presents revenues 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)%

Australian Mining. 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 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 LTCC 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, while seaborne thermal coal sales totaled 11.4 million and 12.2 million tons during those periods, respectively.

Western U.S. Mining. 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. Midwestern U.S. Mining segment revenues decreased slightly in 2013 compared to the prior year, predominantly from a 4.0% decrease in sales volumes.

Trading and Brokerage. 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,		Decrease to Segment Adjusted EBITDA	
	2013	2012	$	%
	(Dollars in millions)			
Australian Mining	$316.6	$938.9	$(622.3)	(66.3)%
Western U.S. Mining	698.3	832.8	(134.5)	(16.2)%
Midwestern U.S. Mining	428.3	427.0	1.3	0.3 %
Trading and Brokerage	(19.9)	119.7	(139.6)	(116.6)%
Total Segment Adjusted EBITDA	$1,423.3	$2,318.4	$(895.1)	(38.6)%

Australian Mining. 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 LTCC 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 2013 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 2012, the resulting benefits were largely offset by lower weighted-average margins experienced across the platform.

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Western U.S. Mining. 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. Adjusted EBITDA from our Midwestern U.S. Mining segment 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. 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 charges of $20.6 million and $7.8 million related to the Gulf Power litigation and Eagle Mining arbitration, respectively. Refer to Note 24. "Commitments and Contingencies" to the accompanying consolidated financial statements for additional information related to those matters.
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	$1,423.3	$2,318.4	$(895.1)	(38.6)%
Corporate and Other Adjusted EBITDA	(376.1)	(481.9)	105.8	22.0%
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)%

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. Those negative factors were partially offset by lower asset impairment and mine closure costs and an improvement in Corporate and Other Adjusted EBITDA.

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Corporate and Other Adjusted EBITDA. The following table presents a summary of the components of Corporate and Other Adjusted EBITDA for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		Increase (Decrease) to Income	
	2013	2012	$	%
	(Dollars in millions)			
Resource management activities [1]	$49.5	$12.8	$36.7	286.7 %
Selling and administrative expenses	(244.2)	(268.8)	24.6	9.2 %
Restructuring and pension settlement costs	(11.9)	—	(11.9)	n.m.
Other operating costs, net [2]	(169.5)	(225.9)	56.4	25.0 %
Corporate and Other Adjusted EBITDA	$(376.1)	$(481.9)	$105.8	22.0 %

(1) Includes gains (losses) on certain surplus coal reserve and surface land sales and property management costs and revenues.

(2) Includes results from equity affiliates (before the impact of related changes in deferred tax asset valuation allowance and amortization of basis difference), gains (losses) on certain asset disposals, costs associated with past mining activities, certain coal royalty expenses and expenses related to our other commercial activities.

The increase in resource management earnings during the year ended December 31, 2013 reflected a second quarter 2013 gain on the sale of non-strategic coal reserves and surface lands in Kentucky ($40.3 million). The reduction in selling and administrative expenses during the year ended December 31, 2014 compared to the prior year largely reflected the impact of our ongoing cost containment efforts. The increase in restructuring and pension settlement costs during the year ended December 31, 2013 compared to the prior year was driven by voluntary and involuntary workforce reduction activity in 2013 in the U.S. The favorable change in "Other operating costs, net" was driven by lower postretirement health care costs due to favorable health care costs trend rates ($25.6 million), improved results from equity affiliates ($22.7 million) due to 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 the 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.

Depreciation, Depletion and Amortization. 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

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The increase in depreciation, depletion and amortization expense 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. 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.

Asset Impairment and Mine Closure Costs. 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.

Settlement Charges Related to the Patriot Bankruptcy Reorganization. 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 Reorganization of Patriot Coal Corporation" to the accompanying consolidated financial statements for additional information surrounding the related matters.

Interest Expense. 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. 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 compared with 2012.

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.

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Income Tax (Benefit) Provision. 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 MRRT ($148.4 million); and
- The impact from the remeasurement of non-U.S. tax accounts as a result of the 2013 weakening of the Australian dollar compared with strengthening in the prior year ($52.2 million); 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.

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 income 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)%

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.

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Loss from Discontinued Operations, Net of Income Taxes. 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 Reorganization of Patriot Coal Corporation" to the accompanying consolidated financial statements, respectively.

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.

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.m.
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.

Outlook

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

Near-Term Outlook

Seaborne coal market segments remain pressured by strong supply and slowing near-term demand growth. We expect stable metallurgical coal supply in 2015, the addition of new global coal-fueled electricity generation and coal import growth in India and Southeast Asia to provide potential catalysts for improvement in market segment conditions going forward. In the U.S., demand for thermal coal was stable in 2014 compared to the prior year despite mild weather in the second half of the year and poor rail performance. We expect 2015 Southern Powder River Basin consumption to be stable compared to 2014 despite lower natural gas prices as rail performance improves and the associated utility coal conservation measures are eliminated.

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Global Macroeconomic Indicators. The World Bank revised its global economic growth estimates downward in its January 2015 Global Economic Prospects. Several factors are driving that revision, including soft commodity prices, persistently low interest rates, increasingly divergent monetary policies and weak world trade. The World Bank noted that a reassessment of risks could also be triggered by a spike in geopolitical tensions, bouts of volatility in commodity markets or financial stress in major emerging market economies. Selected regional and worldwide projections of 2015 and 2016 macroeconomic growth, as measured by recent World Bank forecasts of gross domestic product (GDP), are presented below:

	GDP Growth (%)			
Region:	2015		2016	
U.S.	3.2	%	3.0	%
European Union	1.1	%	1.6	%
China	7.1	%	7.0	%
India	6.4	%	7.0	%
Worldwide	3.0	%	3.3	%

Seaborne Thermal Coal Market Segments and Our Position. Seaborne thermal coal demand has been hampered by sluggish coal generation growth and declining coal generation in Europe due to mild weather and increased renewable generation. According to China Customs data, China's thermal coal imports declined 9% year-over-year to 229 million tonnes in 2014. Recently announced coal quality restrictions and import tariffs in China have created uncertainty and we believe they represent near-term risk for China imports. Such adverse factors were partly offset by higher thermal coal imports in India, which increased by an estimated 20 million tonnes in 2014 on a year-over-year basis. We believe that India's 2015 imports will increase further from 2014 record levels to serve increasing demand from new coal-fueled electricity generation and to replenish stockpiles. We project that 75 gigawatts of new coal-fueled electricity generation will come online globally in 2015, leading to a future increase in seaborne thermal coal demand growth as new generation reaches capacity levels, with China and India accounting for the majority of that growth.

In spite of the continued increases in international thermal coal demand in recent years, the seaborne thermal coal market segment remains well-supplied, which has led to continued decreases in prices for thermal coal originating from Newcastle, Australia. The price for annual contracts commencing April 1, 2014 was settled at $81.80 per tonne, and Newcastle index prices have declined further in early 2015, to near $60 per tonne. We are targeting thermal coal exports of 12 million to 13 million tons from our Australian platform in 2015.

Seaborne Metallurgical Coal Market Segments and Our Position. The World Steel Association (WSA) reported that global steel production grew by 1.2% year-over-year in 2014, a deceleration compared to 3.5% year-over-year growth reported in 2013 due primarily to a slowdown in China’s steel demand. In its October 2014 Short Range Outlook, the WSA forecasted year-over-year apparent steel use growth of 2.0% in 2015.

Seaborne metallurgical coal prices for HQHCC and LV PCI settled at approximately $117 and $99 per tonne, respectively, for quarterly contracts commencing in January 2015, largely in line with prior quarter price levels. Seaborne pricing levels have led to a number of announced production cutbacks, and we expect the first quarter 2015 price settlement to place additional pressure on seaborne suppliers. The majority of announced production cuts have not yet been implemented and are expected to be realized over the next several quarters. We are targeting total 2015 metallurgical coal sales from our Australian platform at 15 million to 16 million tons.

Our total Australian coal sales for 2015 are targeted at 35 million to 37 million tons, including both metallurgical and thermal coal products supplied for export and within Australia.

U.S. Thermal Coal Market Segments and Our Position. Thermal coal consumption for electricity generation was impacted in 2014 from mild weather in the second half of the year and the coal conservation measures implemented by certain electricity generators in response to poor rail performance. Coal accounted for 38.9% of electricity generation in 2014 according to the EIA, while natural gas accounted for 27.2%. Natural gas generation declined less than 1% in 2014 over prior year levels according to the EIA, in spite of higher prices. Electricity generation from coal was stable compared to the prior year according to the EIA, while overall coal production was 1% higher than the prior year. We estimate that coal inventories for Southern Powder River Basin customers were approximately 55 days on a day's-burn basis as of December 31, 2014.

In its February 2015 Short-Term Energy Outlook, the EIA projected that coal will hold a share of 37.8% of U.S. electricity generation in 2015, while electricity generation from natural gas is expected to increase 5% on lower average natural gas prices. Given our expectation of lower average natural gas prices in 2015, we project total U.S. utility coal consumption for electricity generation to decline by 70 million to 80 million tons, though we also expect consumption of Southern Powder River Basin coal to remain stable compared to 2014 driven by the elimination of coal conservation measures due to improved rail performance.

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We are targeting our 2015 U.S. volumes at 190 million to 200 million tons, with approximately 95% of those volumes priced as of December 31, 2014. At that date, we also had approximately 45% to 55% of 2016 volumes priced based on expected 2015 production levels. We anticipate that average realized pricing from our U.S. mining operations will decrease by 2% to 4% on a per-ton basis in 2015 compared to 2014 due to new U.S. coal supply agreements, primarily in our Midwestern U.S. Mining segment, as well as a higher mix of comparatively lower-priced Powder River Basin volumes in our Western U.S. Mining segment.

Operating Cost and Capital Update. In an effort to mitigate pressures from the challenging global coal industry environment, we remain focused on cost containment activities. We expect a decrease in our per-ton U.S. operating costs and expenses in 2015 compared to the prior year. We also expect 2015 operating costs and expenses in Australia to be lower than 2014 levels on a per-ton basis as additional projected savings from a weaker Australian dollar, lower diesel fuel prices, cost containment and productivity programs, an overall improvement in longwall performance and the cost benefit of reduced production from our contractor-operated Burton Mine offset the effects of inflationary pressures.

We also remain focused on efficiently controlling and allocating capital. We are targeting 2015 capital spending levels of $180 million to $200 million, in line with our 2014 spend of $194.4 million.

Long-Term Outlook

While strong supplies and declining seaborne coal prices have tempered near-term expectations, our long-term outlook for international coal market segments is positive based on anticipated growth in Asia. We project that approximately 225 gigawatts of new global coal-fueled generation, as well as industrialization and urbanization trends in China and India, will drive aggregate global thermal and metallurgical coal demand growth of approximately 500 million tonnes between 2014 and 2017. Though we anticipate that seaborne coal supply will also continue to grow during that period, we expect that growth to be outpaced by improved seaborne demand.

The International Energy Agency (IEA) estimates in its World Energy Outlook 2014, Current Policies Scenario, that worldwide primary energy demand will grow 50% between 2012 and 2040. Demand for coal during this time period is projected to rise 51%, and the growth in global electricity generation from coal is expected to be greater than the growth in oil, natural gas, nuclear and solar combined. China and India are expected to account for nearly 75% of the coal-based primary energy demand growth projected from 2012 to 2040.

Under its Current Policies Scenario, the IEA expects coal to retain its strong presence as a fuel for the power sector worldwide. Coal's share of the power generation mix was 41% in 2012. By 2040, the IEA estimates that coal's fuel share of global power generation will be 40% as it continues to have the largest share of worldwide electric power production. Under that scenario, the IEA also projects that global natural gas-fueled electricity generation will have a compound annual growth rate of 2.7%, from 5.1 trillion kilowatt hours in 2012 to 10.8 trillion kilowatt hours in 2040. The total amount of electricity generated from natural gas is expected to be approximately 60% of the total for coal, even in 2040. Hydro, solar and wind are projected to comprise a combined 21% of the 2040 fuel mix versus 19% in 2012. Nuclear power is expected to grow 57%, however its share of total generation is expected to fall from 11% to 9% between 2012 and 2040. Generation from liquid fuels is projected to decline at an average pace of 2.5% annually to a 1.3% share of the 2040 generation mix.

The Current Policies Scenario, which is one of three scenarios presented in the IEA World Energy Outlook 2014, considers government policies that had been enacted or adopted by mid-2014 and does not take into account government policies that may be enacted or adopted in the future. It is prepared by the IEA as a baseline that shows how energy markets would evolve if underlying trends in energy demand and supply are not changed. We believe that the Current Policies Scenario is the most appropriate scenario for our investors to consider based on the substantial uncertainty as to the nature, extent and timing of possible new laws or regulations regarding the extraction or use of our products.

The IEA World Energy Outlook 2014 also contains (1) a New Policies Scenario, which assumes that existing policies are maintained and recently announced commitments and plans, including those yet to be formally adopted, are implemented in a cautious manner, (2) a 450 Scenario, which assumes that policies are adopted that put the world on a pathway that is consistent with having around a 50% chance of limiting the global increase in average temperatures to 2º C in the long term, compared with pre-industrial levels, and (3) an Efficient World Scenario, which assumes that all energy efficiency investments that are economically viable are made and all necessary policies to eliminate market barriers to energy efficiency are adopted.

In the U.S., coal remains a significant fuel for electricity generation, though its share is expected to decline through 2040 due to competition from natural gas and renewables according to the EIA's 2014 Annual Energy Outlook.

Our long-term plans also include advancing projects to expand our presence in Asia, some of which include sourcing third-party coal and partnerships to utilize our mining experience for joint mine development.

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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.

As noted in the "Regulatory Matters -U.S." section included in Part I, Item 1. "Business," on June 2, 2014, the EPA issued proposed rules for regulating carbon dioxide emissions from existing fossil fuel-fired EGUs that would attempt to achieve by 2020 a nationwide carbon dioxide reduction of 25% from 2005 baseline emissions and, by 2030, a reduction of 30% from 2005 baseline emissions. If adopted as proposed, such rules are expected by the EPA to have a significant impact on demand for coal-fired electricity generation in the U.S. and, depending upon the implementation methods adopted by the various states, could have a material adverse effect on our results of operations, financial condition and cash flows in future periods.

Liquidity and Capital Resources

Capital Resources

Our primary sources of cash are proceeds from the sale of our coal production to customers and cash provided by our trading and brokerage activities. To a lesser extent, we also generate cash from the sale of non-strategic assets, including coal reserves and surface lands, borrowings under our committed credit facilities and, from time to time, the issuance of securities.

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

We hold cash balances within the U.S. and in several foreign locations around the world. As of December 31, 2014, approximately $195 million of our cash was held by U.S. entities, with the remaining balance held by foreign subsidiaries in accounts predominantly domiciled in the U.S. A significant majority of the cash held by our foreign subsidiaries is denominated in U.S. dollars. This cash is generally used to support non-U.S. liquidity needs, including capital and operating expenditures in Australia and the foreign operations of our Trading and Brokerage segment. Under current law, earnings repatriated to the U.S. are subject to U.S. federal income tax, less applicable foreign tax credits. We had no undistributed earnings of foreign subsidiaries as of December 31, 2014. Historically, we have not provided deferred taxes on undistributed earnings of foreign subsidiaries because such earnings are considered to be indefinitely reinvested outside of the U.S. We utilize a variety of tax planning and financing strategies with the objective of having our worldwide cash available in the locations where it is needed. When appropriate, we may access our foreign cash in a tax efficient manner. Where local regulations or other circumstances may limit an efficient intercompany transfer of amounts held outside of the U.S., we will continue to utilize those funds for local liquidity needs. We do not expect restrictions or potential taxes on the repatriation of amounts held by our foreign subsidiaries to have a material effect on our overall liquidity, financial condition or results of operations.

Liquidity. In addition to cash and cash equivalents, our liquidity includes the available balances from our $1.65 billion revolving credit facility (as amended, the 2013 Revolver) under the 2013 Credit Facility and an accounts receivable securitization program. As of December 31, 2014, our available liquidity was $2.1 billion, which was substantially comprised of $1.5 billion available for borrowing under the 2013 Revolver (net of outstanding letters of credit of $114.9 million), $298.0 million of cash and cash equivalents and $204.0 million of available capacity from our accounts receivable securitization program (net of amounts drawn and outstanding letters of credit of $30.0 million and $15.0 million, respectively).

Proceeds from the Sale of Non-Strategic Assets. In the first quarter of 2014, the Company sold a non-strategic exploration tenement asset in Australia in exchange for cash proceeds of $62.6 million. In the second quarter of 2014, we entered into an agreement to sell the Wilkie Creek Mine in Australia, which agreement we terminated during the third quarter of 2014 because the potential buyer was unable to meet its subsequent obligations for closing. In the fourth quarter of 2014, we sold non-strategic coal reserves located in Kentucky in exchange for cash proceeds of $29.6 million.

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Capital Requirements

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

We have various bilateral credit and liquidity arrangements with banks, lenders and other counterparties that we use to support the ongoing requirements of our operations, where possible. This credit support is generally provided on an uncommitted basis and is subject to be repriced, or the related capacity reduced or withdrawn, with limited or no notice by such counterparties.

Our cash flows from operations and available liquidity are expected to be sufficient to meet our anticipated capital requirements during 2015 and for the foreseeable future. That expectation is predicated, in part, on the assumption that we will continue to have access to a substantial portion of our maximum borrowing capacity under the 2013 Revolver, if needed in the future. Refer to Part I, Item 1A. “Risk Factors” of this report for a discussion of circumstances that could limit our access to such funds.

We routinely monitor capital and financial market conditions to evaluate the availability of alternative financing sources, including our ability to offer and sell securities under our shelf registration statement. Our ability to obtain external financing and the cost of such financing is affected by our credit ratings, which are periodically reviewed by the three major credit rating agencies. In 2014, each of the three agencies downgraded our corporate credit rating by one notch due, in part, to continued weakness in seaborne coal prices. We continue to believe, based on our current financial condition and credit relationships, that we currently have the ability to access capital and financial markets, if needed. Any further adverse changes in our financial condition, liquidity or credit ratings, or additional uncertainty in capital and financial markets, could negatively impact our ability to access such funds and, in turn, reduce the availability of our cash flows to fund our ongoing operations and discretionary spending. The cost and availability of our bilateral credit and liquidity arrangements are also dependent on our credit profile and to the extent that our credit metrics deteriorate, such credit arrangements may become more costly and/or less available.

Additions to Property, Plant, Equipment and Mine Development. We evaluate our capital project portfolio on an ongoing basis and believe we have the appropriate flexibility to adjust our growth capital spending as appropriate based on any material changes in our cash flows from operations and liquidity position.

Additions to property, plant, equipment and mine development in 2014 included expenditures associated with advancing the reserve development at the Gateway North Mine in the U.S. to replace production from the existing Gateway Mine as its reserves are exhausted in 2015, installing a new longwall to increase productivity at the Metropolitan Mine in Australia and converting the Moorvale Mine in Australia to owner-operator status, which was completed in the third quarter of 2014.

In response to the challenging global environment, we have sought to maintain a controlled, disciplined approach to capital spending in order to preserve liquidity. In 2014, we reduced our additions to property, plant, equipment and mine development to $194.4 million, a 41% decrease compared to the prior year. For 2015, we are again targeting a tightly controlled capital expenditure level of $180 million to $200 million. We expect to allocate approximately 80% of that target to maintaining the existing productive capacity of our global mining platform, with the remainder allotted to development and operational improvement projects. We still plan to defer any significant growth and development projects across our global platform to time periods beyond 2015 and will continue to evaluate the timing associated with those projects based on changes in global coal supply and demand.

Coal Lease Expenditures. Federal coal lease expenditures, which pertain to U.S. federal coal reserves we lease from the U.S. Bureau of Land Management in support of our Western U.S. Mining segment operations, amounted to $276.7 million in 2014. We currently anticipate that our annual federal coal lease expenditures will total approximately $280 million and $250 million in 2015 and 2016, respectively. These expenditures may increase in 2015 and beyond depending upon our participation in and successful bidding on future federal coal leases and similar such arrangements; however, no additional bidding is planned at present at a level of spend comparable to our current obligations.

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Total Indebtedness. Our total indebtedness as of December 31, 2014 and 2014 consisted of the following:

	December 31,	
	2014	2013
	(Dollars in millions)	
2013 Term Loan Facility due September 2020	$1,175.1	$1,185.4
7.375% Senior Notes due November 2016	650.0	650.0
6.00% Senior Notes due November 2018	1,518.8	1,518.8
6.50% Senior Notes due September 2020	650.0	650.0
6.25% Senior Notes due November 2021	1,339.6	1,339.6
7.875% Senior Notes due November 2026	247.6	247.5
Convertible Junior Subordinated Debentures due December 2066	382.3	379.7
Capital lease obligations	22.2	30.5
Other	1.2	0.9
Total	$5,986.8	$6,002.4

Debentures Consent Solicitation. In June 2014, we received sufficient consents from holders of the Debentures to amend the related indenture and eliminate the provisions relating to the mandatory and optional deferral of interest, thereby providing us greater financial and operational flexibility and increased ease of administration with respect to the Debentures. After receiving those consents, we entered into a supplemental indenture reflecting the amendments, which binds all holders of the Debentures. We paid aggregate consent fees of $10.1 million in 2014 in connection with the Debentures consent solicitation, which will be amortized over the remaining term of the Debentures.

Long-term Debt Covenants. Certain of our long-term debt arrangements contain various administrative, reporting, legal and financial covenants, with which we were in compliance as of December 31, 2014. We are permitted to pay dividends, buy and sell assets and make redemptions or repurchases of capital stock, subject to restrictions imposed by the 2013 Credit Facility. That agreement also limits our ability to pay dividends from the top-level Gibraltar holding company of our Australian operations to our domestic subsidiaries in an amount in excess of $500 million per year.

Subsequent to 2014, we entered into the Omnibus Amendment Agreement dated February 5, 2015 (the First Amendment) related to the 2013 Credit Facility which:

- amended the financial maintenance covenants to provide us with greater financial flexibility by lowering the interest coverage ratio and (2) increasing the maximum net first lien secured leverage ratio for the term of the 2013 Credit Facility;
- amended a negative covenant in the 2013 Credit Facility to allow for second lien debt issuances, so long as we remain in compliance with the 2013 Credit Facility; and
- amended certain other negative covenants in the 2013 Credit Facility to (1) reduce our annual cash dividend payments allowable to a maximum of $27.5 million (with carryforward permitted) and the additional general restricted payments basket, which includes dividends, stock repurchases and certain investments, to a maximum of $100.0 million (which amount may increase based on positive earnings during the term of the agreement) and (2) further limit our ability to incur liens, incur debt and make investments.

We do not expect the restrictions imposed by our debt covenants to have a material effect on our overall liquidity or financial condition for the foreseeable future.

Debt Prepayments and Repurchases. As market conditions warrant, we may from time to time repurchase debt securities issued by us, in the open market, in privately negotiated transactions, by tender offer or otherwise.

During the year ended December 31, 2013, we voluntarily prepaid $167.0 million in aggregate principal amount of our previous term loan facility and repurchased $32.4 million of certain Australian private placement bonds with existing cash on hand. We recognized an aggregate loss on debt extinguishment of $5.4 million associated with the foregoing transactions, which was classified in "Interest expense" in the consolidated statement of operations for that period. During the year ended December 31, 2014, we did not make any debt payments in excess of scheduled principal amortization.

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Dividends. We have declared and paid quarterly dividends since our initial public offering in 2001, including $92.3 million paid in 2014 ($0.085 per share each quarter). In connection with our ongoing efforts to manage our cash and preserve liquidity in light of the challenged global coal market conditions experienced in recent years, and in consideration of our contractual obligations discussed further in the "Contractual Obligations" section of this Item 7, we have reduced that quarterly dividend rate to $0.0025 per share for the first quarter of 2015. Our Board of Directors will continue to evaluate our dividend rate on a quarterly basis and the declaration and payment of dividends in the future and the amount of those dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt covenants and other factors that our Board of Directors may deem relevant to such evaluations.

Margin. As part of our Trading and Brokerage segment activities, we may be eligible to receive or required to post margin with an exchange or certain of our over-the-counter contract counterparties. The amount and timing of margin posted can vary with the volume of trades, market price volatility and trade settlements. Total net margin held by us at December 31, 2014 and 2013 was $11.3 million and $35.5 million, respectively. Net cash flows from margin were a net outflow of $24.2 million and $97.7 million for the years ended December 31, 2014 and 2013, respectively.

Settlement Agreement with Patriot and the UMWA. In connection with our settlement agreement with Patriot and the UMWA, on behalf of itself, its represented Patriot employees and its represented Patriot retirees, that became effective in December 2013, we are required to provide total payments of $310 million payable over four years through 2017 to partially fund the newly established voluntary employee beneficiary association (VEBA) and settle all Patriot and UMWA claims involving the Patriot bankruptcy. Those payments included an initial payment of $90 million made in January 2014, comprised of $70 million paid to Patriot and $20 million paid to the VEBA, and subsequent payments of $75 million in 2015, $75 million in 2016 and $70 million in 2017 to be paid to the VEBA. Refer to Note 25. "Matters Related to the Bankruptcy Reorganization of Patriot Coal Corporation" to the accompanying consolidated financial statements for additional information surrounding the settlement agreement.

Pension Contributions. Annual contributions to qualified plans are made in accordance with minimum funding standards and the Company's agreement with the Pension Benefit Guaranty Corporation. Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). During the year ended December 31, 2014, we contributed $3,900,000 million and $1,700,000 million to our qualified and non-qualified pension plans, respectively. We expect to contribute approximately $4.8 million to our pension plans to meet minimum funding requirements for our qualified plans and benefit payments for our non-qualified plans in 2015.

Share Repurchases. As of December 31, 2014, our remaining available capacity for share repurchases under our publicly-announced repurchase program authorized by our Board of Directors was $700.4 million. Repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options.

Shelf Registration. We have an effective shelf registration statement on file with the SEC for an indeterminate number and principal amount of securities that is effective for three years (expires October 19, 2015), after which time we expect to be able to file an automatic shelf registration statement that would become immediately effective for another three-year term. Under this universal shelf registration statement, we have the capacity to offer and sell from time to time securities, including common stock, debt securities, preferred stock, warrants and units.

Historical Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2014 and 2013, as reported in the accompanying consolidated financial statements:

	Year Ended December 31,		Increase (Decrease) to Cash Flow	
	2014	2013	$	%
	(Dollars in millions)			
Net cash provided by operating activities	$336.6	$722.4	$(385.8)	(53.4)%
Net cash used in investing activities	(314.5)	(515.7)	201.2	39.0 %
Net cash used in financing activities	(168.1)	(321.5)	153.4	47.7 %
Net change in cash and cash equivalents	(146.0)	(114.8)	(31.2)	(27.2)%

Cash and cash equivalents at beginning of period	444.0	558.8	(114.8	)	(20.5	)%
Cash and cash equivalents at end of period	$298.0	$444.0	$(146.0	)	(32.9	)%

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Operating Activities. The decrease in net cash provided by operating activities for the year ended December 31, 2014 compared to the prior year was driven by the following:

- The decline in results from operations;
- Aggregate payments to Patriot and the related VEBA made in January 2014 related to our 2013 settlement agreement with Patriot and the UMWA ($90.0 million); and
- The combined impact of changes in the amount drawn under our accounts receivable securitization program and the timing of cash receipts related to customer receivables ($194.4 million); partially offset by
- The timing of disbursements associated with our accounts payable and accrued liabilities ($213.3 million); and
- Lower cash outflows related to the return of net margin held related to our Trading and Brokerage activities ($73.5 million).

Investing Activities. The decrease in net cash used in investing activities for the year ended December 31, 2014 compared to the prior year was driven by lower additions to property, plant, equipment and mine development ($238.1 million, including changes in accrued expenses related to capital expenditures).

Financing Activities. The decrease in net cash used in financing activities for the year ended December 31, 2014 compared to the prior year was driven by the following:

- Lower long-term debt payments, net of proceeds ($182.3 million), mainly due to the impact of $199.4 million in aggregate voluntary debt repayments and repurchases remitted during 2013; partially offset by
- Funds that became restricted in 2014 for the payment of dividends to noncontrolling interests related to the Sumiseki litigation ($42.5 million).

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2014:

	Payments Due By Year				
	Total	Less than 1 Year	2 - 3 Years	4 - 5 Years	More than 5 Years
	(Dollars in millions)				
Long-term debt obligations (principal and interest)	$9,200.8	$390.4	$1,405.1	$2,141.4	$5,263.9
Capital lease obligations (principal and interest)	29.4	9.5	8.3	1.0	10.6
Operating lease obligations(1)	802.0	207.2	374.9	155.6	64.3
Unconditional purchase obligations(2)	42.7	42.7	—	—	—
Coal reserve lease and royalty obligations(3)	627.9	284.6	275.6	38.7	29.0
Take or pay obligations(4)	2,827.2	329.5	656.9	602.2	1,238.6
Other long-term liabilities(5)	3,150.2	280.5	503.8	322.3	2,043.6
Total contractual cash obligations	$16,680.2	$1,544.4	$3,224.6	$3,261.2	$8,650.0

(1) Excludes contingent rents. Refer to Note 13. "Leases" to the accompanying consolidated financial statements for additional discussion of contingent rental agreements.

(2) We routinely enter into purchase agreements with approved vendors for most types of operating expenses in the ordinary course of business. Our specific open purchase orders (which have not been recognized as a liability) under these purchase agreements, combined with any other open purchase orders, are not material and though they are considered enforceable and legally binding, the related terms generally allow us the option to cancel, reschedule or adjust our requirements based on our business needs prior to the delivery of goods or performance of services. Accordingly, the commitments in the table above relate to orders to suppliers for capital purchases.

(3) Includes $0.5 billion of federal coal lease expenditures due in annual installments through 2018, the substantial majority of which end after 2016.

(4) Represents various short- and long-term take or pay arrangements in Australia and the U.S. associated with rail and port commitments for the delivery of coal, including amounts relating to export facilities. Also includes commitments under electricity, water and coal washing agreements with joint ventures.

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

includes $0.2 billion of required payments to the VEBA established in connection with Patriot's bankruptcy emergence, as discussed in further detail in the "Capital Requirements" section above.

We do not expect any of the $40.9 million of net unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

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Off-Balance Sheet Arrangements

In the normal course of business, we are a party to guarantees and financial instruments with off-balance-sheet risk, most of which are not reflected in the accompanying consolidated balance sheets. In our past experience, virtually no claims have been made against these financial instruments. As of February 25, 2015, we do not expect any material losses to result from these guarantees or off-balance-sheet instruments in excess of liabilities already provided for in the consolidated balance sheet as of December 31, 2014.

Accounts Receivable Securitization. We have an accounts receivable securitization program (securitization program) with a maximum capacity of $275.0 million through a wholly-owned, bankruptcy-remote subsidiary (Seller). At December 31, 2014, we had $204.0 million remaining capacity available under the securitization program. Under the securitization program, we contribute trade receivables of most of our U.S. subsidiaries on a revolving basis to the Seller, which then sells the receivables in their entirety to a consortium of unaffiliated asset-backed commercial paper conduits and banks (the Conduits). After the sale, we, as servicer of the assets, collect the receivables on behalf of the Conduits for a nominal servicing fee. We utilize proceeds from the sale of our accounts receivable as an alternative to short-term borrowings under the 2013 Revolver portion of our 2013 Credit Facility, effectively managing our overall borrowing costs and providing an additional source of working capital. The securitization program will expire in April 2016.

The Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Of the receivables sold to the Conduits, a portion of the amount due to the Seller is deferred until the ultimate collection of the underlying receivables. The reduction in accounts receivable as a result of securitization activity with the Conduits was $30.0 million and $100.0 million at December 31, 2014 and 2013, respectively.

Securitization activity has been reflected in the consolidated statements of cash flows as an operating activity because cash received from the Conduits upon the sale of receivables, as well as cash received from the Conduits upon the ultimate collection of receivables, are not subject to significantly different risks given the short-term nature of our trade receivables.

Patriot Bankruptcy Reorganization. As part of our 2013 settlement agreement reached with Patriot and the UMWA that became effective on December 18, 2013, we have provided certain credit support to Patriot, of which $122.2 million remained outstanding as of December 31, 2014. At that date, $81.4 million of this credit took the form of surety bonds issued for the benefit of Patriot beneficiaries, $22.4 million of this credit support took the form of letters of credit issued for the benefit of Patriot beneficiaries and $18.4 million of this credit support took the form of corporate guarantees to Patriot beneficiaries. Approximately $85.0 million of the total credit support ends in 2018. A total of $50.7 million of the credit support (all in the form of surety bonds) relates to Patriot's Coal Act obligations that we agreed to fund at the time of the Patriot spin-off pursuant to the Coal Act Liabilities Assumption Agreement and to Patriot's Federal Black Lung obligations. Upon settlement, we recorded a liability of $28.0 million related to the credit support, which was measured using unobservable Level 3 inputs under the fair value hierarchy to determine the cost to acquire such support. In spite of a subsequent reduction in credit support outstanding, we increased our recorded liability to $57.6 million as of December 31, 2014 due to a credit downgrade of Patriot issued by one of the major credit rating agencies in the fourth quarter of 2014.

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. The definitive settlement agreement reached in 2013, which became effective upon Patriot's emergence from bankruptcy on December 18, 2013, included Patriot’s affirmance of the indemnity relating to such black lung liabilities.

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 us. 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.

Guarantees and Other Financial Instruments with Off-Balance Sheet Risk. See Note 23. "Financial Instruments, Guarantees with Off-Balance Sheet Risk and Other Guarantees" to our consolidated financial statements for a discussion of our guarantees and other financial instruments with off-balance sheet risk.

As previously noted, we have various bilateral credit and liquidity arrangements with banks, lenders and other counterparties that are generally provided on an uncommitted basis and are subject to be repriced, or the related capacity reduced or withdrawn, with limited or no notice by such counterparties. The cost and availability of such arrangements depend, in part, on our credit profile. To the extent that our creditworthiness, as determined by such counterparties, deteriorates, such credit arrangements may become more costly and/or less available.

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Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with U.S. GAAP. We are also required under U.S. GAAP to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

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

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. For our active mining operations, we generally group such assets at the mine level, or the mining complex level for mines that share infrastructure, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for transferability to ongoing operating sites, remaining economic life for use in reclamation-related activities or for expected salvage. For our development and exploration properties and portfolio of surface land and coal reserve holdings, we consider several factors to determine whether to evaluate those assets individually or on a grouped basis for purposes of impairment testing. Such factors include geographic proximity to one another, the expectation of shared infrastructure upon development based on future mining plans and whether it would be most advantageous to bundle such assets in the event of a sale to a third party.

When indicators of impairment are present, we evaluate our long-lived assets used in operations for recoverability by comparing the estimated undiscounted cash flows expected to be generated by those assets under various assumptions to their carrying amounts. If such undiscounted cash flows indicate that the carrying value of the asset group is not recoverable, impairment losses are measured by comparing the estimated fair value of the asset group to its carrying amount. As quoted market prices are unavailable for our individual mining operations, fair value is determined through the use of an expected present value technique based on the income approach, except for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from the Company's long-range mine planning. In those cases, a market approach is utilized based on the most comparable market multiples available. The estimated future cash flows and underlying assumptions used to assess recoverability and, if necessary, measure the fair value of our long-lived assets are derived from those developed in connection with our planning and budgeting process. We believe our assumptions are consistent with those a market participant would use for valuation purposes. The most critical assumptions underlying our projections include those surrounding future coal prices for unpriced coal, production costs (including costs for labor, commodity supplies and contractors), transportation costs, foreign currency exchange rates and a risk-adjusted, after-tax cost of capital (all of which generally constitute unobservable Level 3 inputs under the fair value hierarchy), in addition to market multiples for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from the Company's long-range mine planning (which generally constitute Level 2 inputs under the fair value hierarchy).

Impairment of long-lived assets included in continuing operations was $149.7 million for the year ended December 31, 2014. The assumptions used are based on our best knowledge at the time we prepare our analysis but can vary significantly due to changes in coal supply and demand, regulatory issues, unforeseen mining conditions, commodity prices and cost of labor. These types of changes may cause the Company to be unable to recover all or a portion of the carrying value of its long-lived assets. Because of the volatile and cyclical nature of the international seaborne coal markets, it is reasonably possible that seaborne metallurgical coal prices may not improve or decrease further in the near term, which may result in the need for future adjustments to the carrying value of the Company's long-lived mining assets. The Company's long-lived assets whose recoverability and values are most sensitive to near-term pricing are certain non-strategic Australian undeveloped coal properties. Such assets had an aggregate carrying value of $59.9 million as of December 31, 2014. The Company conducted a review of those assets for recoverability as of December 31, 2014 and determined that, other than the charges recorded, no further impairment charge was necessary as of that date.

See Note 2. "Asset Impairment and Mine Closure Costs" to our consolidated financial statements for additional information regarding impairment charges.

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Income Taxes. We account for income taxes in accordance with accounting guidance which requires deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is “more likely than not” that some portion or all of the deferred tax asset will not be realized. In our evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. As of December 31, 2014, we had valuation allowances for income taxes totaling $1,169.0 million. If actual results differ from the assumptions made in our annual evaluation of our valuation allowance, we may record a change in valuation allowance through income tax expense in the period such determination is made.

Our liability for unrecognized tax benefits contains uncertainties because management is required to make assumptions and to apply judgment to estimate the exposures associated with our various filing positions. We recognize the tax benefit from an uncertain tax position only if it is “more likely than not” that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position must be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. As of December 31, 2014, we had net unrecognized tax benefits of $40.9 million included in recorded liabilities in the consolidated balance sheet. We believe that our judgments and estimates are reasonable; however, to the extent we prevail in matters for which liabilities have been established, or are required to pay amounts in excess of our recorded liabilities, our effective tax rate in a given period could be materially affected.

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

Postretirement Benefit and Pension Liabilities. We have long-term liabilities for our employees’ postretirement benefit costs and defined benefit pension plans. Liabilities for postretirement benefit costs are not funded. Our pension obligations are funded in accordance with the provisions of applicable laws. Expense for the year ended December 31, 2014 for postretirement benefit costs and pension liabilities totaled $99.4 million (including $8.7 million pension settlement charges), while employer contributions were $49.9 million.

Each of these liabilities is actuarially determined and we use various actuarial assumptions, including the discount rate, future cost trends, demographic assumptions and expected asset returns to estimate the costs and obligations for these items. Our discount rate is determined by utilizing a hypothetical bond portfolio model which approximates the future cash flows necessary to service our liabilities. We make assumptions related to future trends for medical care costs in the estimates of postretirement benefit costs. Our medical trend assumption is developed by annually examining the historical trend of cost per claim data. In addition, we make assumptions related to rates of return on plan assets in the estimates of pension obligations. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Moreover, regulatory changes could affect our obligation to satisfy these or additional obligations.

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

	For Year Ended December 31, 2014	
	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Health care cost trend rate:		
Effect on total net periodic postretirement benefit cost	$9.5	$(8.5)
Effect on total postretirement benefit obligation	$80.6	$(70.3)

	For Year Ended December 31, 2014

	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic postretirement benefit cost	$(2.6)	$2.5
Effect on total postretirement benefit obligation	$(41.8)	$44.0

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

	For Year Ended December 31, 2014	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic pension cost	$(7.1)	$7.7
Effect on defined benefit pension plans' funded status	$52.2	$(57.4)
Expected return on assets:		
Effect on total net periodic pension cost	$(4.0)	$4.0

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

Asset Retirement Obligations. Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with applicable reclamation laws in the U.S. and Australia as defined by each mining permit. Asset retirement obligations are determined for each mine using various estimates and assumptions including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage and the timing of these cash flows, discounted using a credit-adjusted, risk-free rate. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the reclamation activities), the obligation and asset are revised to reflect the new estimate after applying the appropriate credit-adjusted, risk-free rate. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Moreover, regulatory changes could increase our obligation to perform reclamation and mine closing activities. Asset retirement obligation expenses for the year ended December 31, 2014 were $81.0 million, and payments totaled $20.7 million. See Note 14. "Asset Retirement Obligations" to our consolidated financial statements for additional information regarding our asset retirement obligations.

Fair Value Measurements of Financial Instruments. We evaluate the quality and reliability of the assumptions and data used in our Trading and Brokerage segment to measure fair value in the three level hierarchy, Levels 1, 2 and 3. Level 3 fair value measurements are those where inputs are unobservable, or observable but cannot be market-corroborated, requiring us to make assumptions about pricing by market participants. Commodity swaps and options and physical commodity purchase/sale contracts transacted in less liquid markets or contracts, such as long-term arrangements, with limited price availability were classified in Level 3. Indicators of less liquid markets are those with periods of low trade activity or when broker quotes reflect wide pricing spreads. Generally, these instruments or contracts are valued using internally generated models that include forward pricing curve quotes from one to three reputable brokers. Our valuation techniques also include basis adjustments for heat rate, sulfur and ash content, port and freight costs, and credit risk. We validate our valuation inputs with third-party information and settlement prices from other sources where available. We also consider credit and nonperformance risk in the fair value measurement by analyzing the counterparty's exposure balance, credit rating and average default rate, net of any counterparty credit enhancements (e.g., collateral), as well as our own credit rating for financial liability trading positions.

We have consistently applied these valuation techniques in all periods presented, and believe we have obtained the most accurate information reasonably available for the types of derivative contracts held. Valuation changes from period to period for each level will increase or decrease depending on: (1) the relative change in fair value for positions held, (2) new positions added, (3) realized amounts for completed trades, and (4) transfers between levels. Our coal trading strategies utilize various swaps and derivative physical contracts. Periodic changes in fair value for purchase and sale positions, which are executed to lock in coal trading spreads, occur in each level and therefore the overall change in value of our coal trading platform requires consideration of valuation changes across all levels.

At December 31, 2014 and 2013, 9% ($2.1 million) and 7% ($2.1 million), respectively, of our net financial asset trading positions were categorized as Level 3. See Note 7. "Coal Trading" to our consolidated financial statements for additional information regarding fair value measurements of our net financial asset trading positions.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

See Note 1. "Summary of Significant Accounting Policies" to our consolidated financial statements for a discussion of newly adopted accounting standards and accounting standards not yet implemented.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The potential for changes in the market value of our coal and freight-related trading, crude oil, diesel fuel, natural gas, explosives, interest rate and foreign currency contract portfolios, as applicable, is referred to as “market risk.” Market risk related to our coal trading and freight-related contract portfolio, which includes bilaterally-settled and over-the-counter (OTC) exchange-settled trading, in addition to, from time to time, the brokered trading of coal, is evaluated using a value at risk (VaR) analysis. VaR analysis is not used to evaluate our non-trading diesel fuel, explosives, foreign currency or interest rate hedging portfolios, as applicable, or coal trading activities we employ in support of coal production (as discussed below). We attempt to manage market price risks through diversification, controlling position sizes and executing hedging strategies. Due to a lack of quoted market prices and the long-term, illiquid nature of the positions, we have not quantified market price risk related to our non-trading, long-term coal supply agreement portfolio.

Coal Trading Activities and Related Commodity Price Risk

Coal Price Risk Monitored Using VaR. We engage in direct and brokered trading of physical coal and freight-related commodities in OTC markets. These activities give rise to commodity price risk, which represents the potential loss that can be caused by an adverse change in the market value of a particular commitment. We actively measure, monitor, manage and hedge market price risk due to current and anticipated trading activities to remain within risk limits prescribed by management. For example, we have policies in place that limit the amount of market price risk, as measured by VaR, that we may assume at any point in time from our trading and brokerage activities.

We generally account for our coal trading activities using the fair value method, which requires us to reflect contracts with third parties that meet the definition of a derivative at market value in our consolidated financial statements, with the exception of contracts for which we have elected to apply the normal purchases and normal sales exception. Our trading portfolio included futures, forwards, swaps and options as of December 31, 2014. The use of VaR allows us to quantify in dollars, on a daily basis, a measure of price risk inherent in our trading portfolio. VaR represents the expected loss in portfolio value due to adverse market price movements over a defined time horizon (liquidation period) within a specified confidence level. Our VaR model is based on a variance/co-variance approach, which captures our potential loss exposure related to future, forward, swap and option positions. Our VaR model assumes a 5- to 15-day holding period, dependent upon the products within our portfolio, at the time of VaR measurement and produces an output corresponding with a 95% one-tailed confidence interval, which means that there is a one in 20 statistical chance that our portfolio could lose more than the VaR estimates during the assumed liquidation period. Our volatility calculation incorporates an exponentially weighted moving average algorithm based on price movements during the previous 60 market days, which makes our volatility more representative of recent market conditions while still reflecting an awareness of historical price movements. VaR does not estimate the maximum potential loss expected in the 5% of the time that changes in the portfolio value during the assumed liquidation period is expected to exceed measured VaR. We use stress testing and scenario analysis to help provide visibility in such cases, as discussed further below.

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

During the year ended December 31, 2014, the actual low, high and average VaR was $1.0 million, $4.6 million and $2.3 million, respectively.

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

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Future Realization. As of December 31, 2014, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio Total	
2015	77	%
2016	19	%
2017	3	%
2018	1	%
	100	%

We also monitor other types of risk associated with our coal trading activities, including credit, market liquidity and counterparty nonperformance.

Credit and Nonperformance Risk

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

Non-Coal Trading. The fair value of our non-coal trading derivative assets and liabilities reflects adjustments for credit risk. We manage our counterparty risk from our hedging activities related to foreign currency, fuel, explosives and interest rate exposures, as applicable, through established credit standards, diversification of counterparties, utilization of investment grade commercial banks, adherence to established tenor limits based on counterparty creditworthiness and continual monitoring of that creditworthiness. To reduce our credit exposure for these hedging activities, we seek to enter into netting agreements with counterparties that permit us to offset receivable and payables with such counterparties in the event of default. We also continually monitor counterparties for nonperformance risk, if present, on a case-by-case basis.

Foreign Currency Risk

We utilize currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 6 "Derivatives and Fair Value Measurements" to our consolidated financial statements. Assuming we had no foreign currency hedges in place, our exposure in operating costs and expenses due to a $0.05 change in the Australian dollar/U.S. dollar exchange rate is approximately $117 million for 2015. Taking into consideration hedges in place as of December 31, 2014, our net exposure to the same rate change is approximately $33 million for 2015. The notional amounts of our foreign currency hedge contracts as of December 31, 2014 are noted in the "Notional Amounts and Fair Value" section of Note 6 to our consolidated financial statements, which information is incorporated herein by reference.

Other Non-Coal Trading Activities — Commodity Price Risk

Long-Term Coal Contracts. We predominantly manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements (those with terms longer than one year) to the extent possible, rather than through the use of derivative instruments. Sales under such agreements comprised approximately 83%, 80% and 89% of our worldwide sales (by volume) for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, approximately 95% of our projected 2015 U.S. coal production is priced at planned production levels of 190 million to 200 million tons. We had 90% to 95% of expected full year 2015 seaborne thermal coal volumes of 12 million to 13 million tons available for pricing at December 31, 2014. We expect near-term macroeconomic movements to dictate quarterly metallurgical coal pricing for the remainder of 2015 and we are targeting total 2015 metallurgical coal sales of approximately 15 million to 16 million tons.

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Diesel Fuel and Explosives Hedges. We manage commodity price risk of the diesel fuel and explosives used in our mining activities through the use of cost pass-through contracts and derivatives, primarily swaps. Notional amounts outstanding under fuel-related and explosives-related derivative swap contracts are noted in the "Notional Amounts and Fair Value" section of Note 6 to our consolidated financial statements, which information is incorporated herein by reference.

We expect to consume 150 to 160 million gallons of diesel fuel in 2015. Assuming we had no hedges in place, a $10 per barrel change in the price of crude oil (the primary component of a refined diesel fuel product) would increase or decrease our annual diesel fuel costs by approximately $38 million based on our expected usage. Taking into consideration hedges in place as of December 31, 2014, our net exposure to the same change in the price of crude oil is approximately $13 million.

We expect to consume 385,000 to 395,000 tons of explosives during 2015 in the U.S. From time to time, we manage this risk through the use of derivatives, though as of December 31, 2014, we had no hedges in place related to our future explosives spend. An assumed price change in natural gas (often a key component in the production of explosives) of one dollar per mmBtu would result in an increase or decrease in our annual explosives costs of approximately $6 million based on our expected usage.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. From time to time, we manage our debt to achieve a certain ratio of fixed-rate debt and variable-rate debt as a percent of net debt through the use of various hedging instruments. As of December 31, 2014, we had $4.8 billion of fixed-rate borrowings and $1.2 billion of variable-rate borrowings outstanding and had no interest rate swaps in place. A one percentage point increase in interest rates would result in an annualized increase to interest expense of approximately $12 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $759 million in the estimated fair value of these borrowings.

Item 8. Financial Statements and Supplementary Data.

See Part IV, Item 15. "Exhibits, Financial Statement Schedules" of this report for the information required by this Item 8, which information is incorporated by reference herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures are designed to, among other things, provide reasonable assurance that material information, both financial and non-financial, and other information required under the securities laws to be disclosed is accumulated and communicated to senior management, including the principal executive officer and principal financial officer, on a timely basis. As of December 31, 2014, the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of December 31, 2014, and concluded that such controls and procedures are effective to provide reasonable assurance that the desired control objectives were achieved.

Changes in Internal Control Over Financial Reporting

We periodically review our internal control over financial reporting as part of our efforts to ensure compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. In addition, we routinely review our system of internal control over financial reporting to identify potential changes to our processes and systems that may improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new systems, consolidating the activities of acquired business units, migrating certain processes to our shared services organizations, formalizing and refining policies and procedures, improving segregation of duties and adding monitoring controls. In addition, when we acquire new businesses, we incorporate our controls and procedures into the acquired business as part of our integration activities. There have been no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Management's Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. Our internal control framework and processes are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Because of inherent limitations, any system of internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control - Integrated Framework (2013). Based on this assessment, management concluded that the Company's internal control over financial reporting was effective to provide reasonable assurance that the desired control objectives were achieved as of December 31, 2014.

Our Independent Registered Public Accounting Firm, Ernst & Young LLP, has audited our internal control over financial reporting, as stated in their unqualified opinion report included herein.

/s/ Gregory H. Boyce	/s/ Michael C. Crews
Gregory H. Boyce	Michael C. Crews
Chairman and Chief Executive Officer	Executive Vice President and Chief Financial Officer
February 25, 2015	

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Peabody Energy Corporation

We have audited Peabody Energy Corporation's (the Company's) internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Peabody Energy Corporation as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014 of Peabody Energy Corporation and our report dated February 25, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri

February 25, 2015

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Item 9B. Other Information.
None.
PART III
Item 10.Directors, Executive Officers and Corporate Governance.
The information required by Item 401 of Regulation S-K is included under the caption “Election of Directors-Director Qualifications” in our 2015 Proxy Statement and in Part I, Item 1. "Business" of this report under the caption “Executive Officers of the Company.” The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions “Ownership of Company Securities — Section 16(a) Beneficial Ownership Reporting Compliance,” “Corporate Governance Matters” and “Information Regarding Board of Directors and Committees-Committees of the Board of Directors-Audit Committee” in our 2015 Proxy Statement. Such information is incorporated herein by reference.
Item 11.Executive Compensation.
The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K is included under the captions “Executive Compensation,” “Compensation Committee Interlocks and Insider Participation” and “Report of the Compensation Committee” in our 2015 Proxy Statement and is incorporated herein by reference.
Item 12.Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
The information required by Item 403 of Regulation S-K is included under the caption “Ownership of Company Securities” in our 2015 Proxy Statement and is incorporated herein by reference.
Equity Compensation Plan Information
As required by Item 201(d) of Regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2014:

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights		Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights		Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))	
Equity compensation plans approved by security holders	1,787,584	(1)	$40.20	(2)	8,627,299	(3)
Equity compensation plans not approved by security holders	—		—		—	
Total	1,787,584		$40.20		8,627,299	

(1) Includes 156,028 shares issuable pursuant to outstanding deferred stock units and 36,861 shares issuable pursuant to outstanding performance units.
(2) The weighted-average exercise price shown in the table does not take into account outstanding deferred stock units or performance awards.
(3) Includes 1,035,966 shares available for issuance under our U.S. Employee Stock Purchase Plan and 804,551 shares available for issuance under our Australian Employee Stock Purchase Plan.

Refer to Note 18. "Share-Based Compensation" to the accompanying consolidated financial statements for additional information regarding the material features of our equity compensation plans.
Item 13.Certain Relationships and Related Transactions, and Director Independence.

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions "Policy for Approval of Related Person Transactions" and "Information Regarding Board of Directors and Committees-Director Independence" in our 2015 Proxy Statement and is incorporated herein by reference.

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Item 14.Principal Accounting Fees and Services.

The information required by Item 9(e) of Schedule 14A is included under the caption “Fees Paid to Independent Registered Public Accounting Firm” in our 2015 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15.Exhibits, Financial Statement Schedules.

(a) Documents Filed as Part of the Report

(1) Financial Statements.

The following consolidated financial statements of Peabody Energy Corporation and the report thereon of the independent registered public accounting firm are included herein on the pages indicated:

(2) Financial Statement Schedules.

The following financial statement schedule of Peabody Energy Corporation is at the page indicated:

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

(3) Exhibits.

See Exhibit Index hereto.

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

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SIGNATURES

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

PEABODY ENERGY CORPORATION

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

Date: February 25, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons, on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ GREGORY H. BOYCE Gregory H. Boyce	Chairman and Chief Executive Officer, Director (principal executive officer)	February 25, 2015
/s/ MICHAEL C. CREWS Michael C. Crews	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 25, 2015
/s/ WILLIAM A. COLEY William A. Coley	Director	February 25, 2015
/s/ WILLIAM E. JAMES William E. James	Director	February 25, 2015
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 25, 2015
/s/ GLENN L. KELLOW Glenn L. Kellow	Director and Chief Executive Officer-elect	February 25, 2015
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 25, 2015
/s/ ROBERT A. MALONE Robert A. Malone	Director	February 25, 2015
/s/ WILLIAM C. RUSNACK William C. Rusnack	Director	February 25, 2015
/s/ MICHAEL W. SUTHERLIN Michael W. Sutherlin	Director	February 25, 2015
/s/ JOHN F. TURNER John F. Turner	Director	February 25, 2015
/s/ SANDRA A. VAN TREASE Sandra A. Van Trease	Director	February 25, 2015

/s/ HEATHER A. WILSON Heather A. Wilson	Director	February 25, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Peabody Energy Corporation

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation (the Company) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, changes in stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Peabody Energy Corporation’s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 25, 2015 expressed unqualified opinion thereon.

/s/ Ernst & Young LLP
St. Louis, Missouri
February 25, 2015

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2014	2013	2012
	(Dollars in millions, except per share data)		
Revenues			
Sales	$6,132.7	$6,380.0	$7,041.7
Other revenues	659.5	633.7	1,035.8
Total revenues	6,792.2	7,013.7	8,077.5
Costs and expenses			
Operating costs and expenses (exclusive of items shown separately below)	5,716.9	5,729.1	5,932.7
Depreciation, depletion and amortization	655.7	740.3	663.4
Asset retirement obligation expenses	81.0	66.5	67.0
Selling and administrative expenses	227.1	244.2	268.8
Restructuring and pension settlement charges	26.0	11.9	—
Other operating (income) loss:			
Net gain on disposal or exchange of assets	(41.4)	(52.6)	(17.1)
Asset impairment and mine closure costs	154.4	528.3	929.0
Settlement charges related to the Patriot bankruptcy reorganization	—	30.6	—
Loss from equity affiliates	107.6	40.2	61.2
Operating (loss) profit	(135.1)	(324.8)	172.5
Interest expense	428.2	425.2	405.6
Interest income	(15.4)	(15.7)	(24.5)
Loss from continuing operations before income taxes	(547.9)	(734.3)	(208.6)
Income tax provision (benefit)	201.2	(448.3)	262.3
Loss from continuing operations, net of income taxes	(749.1)	(286.0)	(470.9)
Loss from discontinued operations, net of income taxes	(28.2)	(226.6)	(104.2)
Net loss	(777.3)	(512.6)	(575.1)
Less: Net income attributable to noncontrolling interests	9.7	12.3	10.6
Net loss attributable to common stockholders	$(787.0)	$(524.9)	$(585.7)
Loss from continuing operations			
Basic loss per share	$(2.83)	$(1.12)	$(1.80)
Diluted loss per share	$(2.83)	$(1.12)	$(1.80)
Net loss attributable to common stockholders			
Basic loss per share	$(2.94)	$(1.97)	$(2.19)
Diluted loss per share	$(2.94)	$(1.97)	$(2.19)
Dividends declared per share	$0.34	$0.34	$0.34

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2014	2013	2012
	(Dollars in millions)		
Net loss	$(777.3)	$(512.6)	$(575.1)
Other comprehensive (loss) income, net of income taxes:			
Net change in unrealized (losses) gains on available-for-sale securities (net of respective tax (benefit) provision of ($0.5), $0.5 and $4.0)			
Unrealized holding losses on available-for-sale securities	(3.7)	(12.3)	(15.5)
Reclassification for realized losses included in net loss	2.9	12.8	22.5
Net change in unrealized (losses) gains on available-for-sale securities	(0.8)	0.5	7.0
Net unrealized (losses) gains on cash flow hedges (net of respective tax benefit of ($54.6), ($300.0) and ($3.9))			
(Decrease) increase in fair value of cash flow hedges	(195.0)	(333.6)	350.4
Reclassification for realized gains included in net loss	(10.2)	(209.6)	(298.6)
Net unrealized (losses) gains on cash flow hedges	(205.2)	(543.2)	51.8
Postretirement plans and workers' compensation obligations (net of respective tax (benefit) provision of ($10.3), $121.7 and $43.9)			
Prior service credit (cost) for the period	11.4	(1.4)	20.1
Net actuarial (loss) gain for the period	(142.7)	110.9	—
Amortization of actuarial loss and prior service cost included in net loss	32.7	95.7	55.4
Postretirement plans and workers' compensation obligations	(98.6)	205.2	75.5
Foreign currency translation adjustment	(41.0)	(92.7)	19.1
Other comprehensive (loss) income, net of income taxes	(345.6)	(430.2)	153.4
Comprehensive loss	(1,122.9)	(942.8)	(421.7)
Less: Comprehensive income attributable to noncontrolling interests	9.7	12.3	10.6
Comprehensive loss attributable to common stockholders	$(1,132.6)	$(955.1)	$(432.3)

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	2013
	(Amounts in millions, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$298.0	$444.0
Accounts receivable, net of allowance for doubtful accounts of $5.8 at December 31, 2014 and $7.4 at December 31, 2013	563.1	557.9
Inventories	406.5	506.7
Assets from coal trading activities, net	57.6	36.1
Deferred income taxes	80.0	66.4
Other current assets	305.8	381.6
Total current assets	1,711.0	1,992.7
Property, plant, equipment and mine development, net	10,577.3	11,082.5
Deferred income taxes	0.7	7.8
Investments and other assets	902.1	1,050.4
Total assets	$13,191.1	$14,133.4
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$21.2	$31.7
Liabilities from coal trading activities, net	32.7	6.1
Accounts payable and accrued expenses	1,809.2	1,764.0
Total current liabilities	1,863.1	1,801.8
Long-term debt, less current maturities	5,965.6	5,970.7
Deferred income taxes	89.1	40.9
Asset retirement obligations	722.3	691.8
Accrued postretirement benefit costs	781.9	684.0
Other noncurrent liabilities	1,042.6	996.3
Total liabilities	10,464.6	10,185.5
Stockholders' equity		
Preferred Stock — $0.01 per share par value; 10.0 shares authorized, no shares issued or outstanding as of December 31, 2014 or December 31, 2013	—	—
Perpetual Preferred Stock — 0.8 shares authorized, no shares issued or outstanding as of December 31, 2014 or December 31, 2013	—	—
Series Common Stock — $0.01 per share par value; 40.0 shares authorized, no shares issued or outstanding as of December 31, 2014 or December 31, 2013	—	—
Common Stock — $0.01 per share par value; 800.0 shares authorized, 285.7 shares issued and 271.7 shares outstanding as of December 31, 2014 and 283.9 shares issued and 270.1 shares outstanding as of December 31, 2013	2.9	2.8
Additional paid-in capital	2,383.3	2,340.0
Treasury stock, at cost — 14.0 shares as of December 31, 2014 and 13.8 shares as of December 31, 2013	(467.1)	(464.7)
Retained earnings	1,570.5	2,449.8
Accumulated other comprehensive loss	(764.8)	(419.2)
Peabody Energy Corporation stockholders' equity	2,724.8	3,908.7
Noncontrolling interests	1.7	39.2

Total stockholders’ equity	2,726.5	3,947.9
Total liabilities and stockholders’ equity	$13,191.1	$14,133.4

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
	(Dollars in millions)		
Cash Flows From Operating Activities			
Net loss	$(777.3)	$(512.6)	$(575.1)
Loss from discontinued operations, net of income taxes	28.2	226.6	104.2
Loss from continuing operations, net of income taxes	(749.1)	(286.0)	(470.9)
Adjustments to reconcile loss from continuing operations, net of income taxes to net cash provided by operating activities:			
Depreciation, depletion and amortization	655.7	740.3	663.4
Noncash interest expense	23.6	32.0	20.7
Deferred income taxes	231.9	(434.1)	(2.6)
Share-based compensation	46.8	50.9	45.4
Asset impairment and mine closure costs	154.4	528.3	929.0
Settlement charges related to the Patriot bankruptcy reorganization	—	30.6	—
Net gain on disposal or exchange of assets	(41.4)	(52.6)	(17.1)
Loss from equity affiliates	107.6	40.2	61.2
Monetization of foreign currency hedge positions	—	—	151.8
Gains on previously monetized foreign currency hedge positions	(136.9)	—	—
Changes in current assets and liabilities:			
Accounts receivable	55.4	104.8	285.3
Change in receivable from accounts receivable securitization program	(70.0)	75.0	(125.0)
Inventories	104.9	39.9	(112.9)
Net assets from coal trading activities	(10.1)	(83.7)	125.2
Other current assets	7.7	3.1	10.3
Accounts payable and accrued expenses	(29.2)	(108.9)	(87.8)
Asset retirement obligations	60.3	45.5	46.4
Workers’ compensation obligations	2.2	7.3	9.4
Accrued postretirement benefit costs	9.6	17.0	38.9
Accrued pension costs	28.3	51.8	32.4
Other, net	(10.7)	(21.3)	(3.3)
Net cash provided by continuing operations	441.0	780.1	1,599.8
Net cash used in discontinued operations	(104.4)	(57.7)	(84.7)
Net cash provided by operating activities	336.6	722.4	1,515.1
Cash Flows From Investing Activities			
Additions to property, plant, equipment and mine development	(194.4)	(328.4)	(986.0)
Changes in accrued expenses related to capital expenditures	(16.6)	(120.7)	104.7
Federal coal lease expenditures	(276.7)	(276.8)	(276.5)
Investment in Prairie State Energy Campus	—	—	(10.7)
Proceeds from disposal of assets, net of notes receivable	203.7	178.3	147.9
Purchases of debt and equity securities	(15.1)	(22.8)	(46.7)
Proceeds from sales and maturities of debt and equity securities	13.5	22.9	46.4
Purchases of short-term investments	—	—	(4.8)
Maturity of short-term investments	—	4.8	—
Contributions to joint ventures	(529.8)	(671.7)	(824.0)
Distributions from joint ventures	534.2	722.9	823.0
Advances to related parties	(33.7)	(42.1)	(148.0)

Repayment of loans from related parties	5.4	25.2	110.8
Other, net	(5.0)	(5.8)	(6.2)
Net cash used in continuing operations	(314.5)	(514.2)	(1,070.1)
Net cash used in discontinued operations	—	(1.5)	(22.0)
Net cash used in investing activities	(314.5)	(515.7)	(1,092.1)

See accompanying notes to consolidated financial statements

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

	Year Ended December 31,		
	2014	2013	2012
	(Dollars in millions)		
Cash Flows From Financing Activities			
Proceeds from long-term debt	$1.1	$1,188.0	$0.8
Repayments of long-term debt	(21.0)	(1,390.2)	(415.8)
Payment of deferred financing costs	(10.1)	(22.8)	(6.9)
Dividends paid	(92.3)	(91.7)	(91.9)
Common stock repurchase	—	—	(99.9)
Excess tax benefits related to share-based compensation	—	—	8.3
Acquisition of MCG Coal Holdings Pty Ltd noncontrolling interests	—	—	(49.8)
Restricted cash for distributions to noncontrolling interests	(42.5)	—	—
Other, net	(3.3)	(4.8)	(8.1)
Net cash used in financing activities	(168.1)	(321.5)	(663.3)
Net change in cash and cash equivalents	(146.0)	(114.8)	(240.3)
Cash and cash equivalents at beginning of year	444.0	558.8	799.1
Cash and cash equivalents at end of year	$298.0	$444.0	$558.8

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Peabody Energy Corporation Stockholders' Equity						
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Stockholders' Equity
	(Dollars in millions)						
December 31, 2011	$2.8	$2,234.0	$(353.3)	$3,744.0	$(142.4)	$30.7	$5,515.8
Net (loss) income	—	—	—	(585.7)	—	10.6	(575.1)
Net change in unrealized gains on available-for-sale securities (net of $4.0 tax provision)	—	—	—	—	7.0	—	7.0
Net unrealized gains on cash flow hedges (net of $3.9 tax benefit)	—	—	—	—	51.8	—	51.8
Postretirement plans and workers' compensation obligations (net of $43.9 tax provision)	—	—	—	—	75.5	—	75.5
Foreign currency translation adjustment	—	—	—	—	19.1	—	19.1
Dividends paid	—	—	—	(91.9)	—	—	(91.9)
Share-based compensation	—	45.4	—	—	—	—	45.4
Excess tax benefits related to share-based compensation	—	8.3	—	—	—	—	8.3
Stock options exercised	—	2.4	—	—	—	—	2.4
Employee stock purchases	—	7.0	—	—	—	—	7.0
Repurchase of employee common stock relinquished for tax withholding	—	—	(8.4)	—	—	—	(8.4)
Common stock repurchase	—	—	(99.9)	—	—	—	(99.9)
MCG Coal Holdings Pty Ltd noncontrolling interests at conversion	—	—	—	—	—	39.0	39.0
Acquisition of MCG Coal Holdings Pty Ltd noncontrolling interests	—	(10.8)	—	—	—	(39.0)	(49.8)
Distributions to noncontrolling interests	—	—	—	—	—	(7.4)	(7.4)
December 31, 2012	$2.8	$2,286.3	$(461.6)	$3,066.4	$11.0	$33.9	$4,938.8
Net (loss) income	—	—	—	(524.9)	—	12.3	(512.6)
Net change in unrealized gains on available-for-sale securities (net of $0.5 tax provision)	—	—	—	—	0.5	—	0.5
Net unrealized losses on cash flow hedges (net of $300.0 tax benefit)	—	—	—	—	(543.2)	—	(543.2)
Postretirement plans and workers' compensation obligations (net of $121.7 tax provision)	—	—	—	—	205.2	—	205.2

Foreign currency translation adjustment	—	—	—	—	(92.7)	—	(92.7)
Dividends paid	—	—	—	(91.7)	—	—	(91.7)
Share-based compensation	—	50.9	—	—	—	—	50.9
Write-off of excess tax benefits related to share-based compensation	—	(4.5)	—	—	—	—	(4.5)
Stock options exercised	—	1.0	—	—	—	—	1.0
Employee stock purchases	—	6.3	—	—	—	—	6.3
Repurchase of employee common stock relinquished for tax withholding	—	—	(3.1)	—	—	—	(3.1)
Distributions to noncontrolling interests	—	—	—	—	—	(7.0)	(7.0)
December 31, 2013	$2.8	$2,340.0	$(464.7)	$2,449.8	$ (419.2)	$ 39.2	$3,947.9
Net (loss) income	—	—	—	(787.0)	—	9.7	(777.3)
Net change in unrealized losses on available-for-sale-securities (net of $0.5 tax benefit)	—	—	—	—	(0.8)	—	(0.8)
Net unrealized losses on cash flow hedges (net of $54.6 tax benefit)	—	—	—	—	(205.2)	—	(205.2)
Postretirement plans and workers' compensation obligations (net of $10.3 tax benefit)	—	—	—	—	(98.6)	—	(98.6)
Foreign currency translation adjustment	—	—	—	—	(41.0)	—	(41.0)
Dividends paid	—	—	—	(92.3)	—	—	(92.3)
Share-based compensation	—	46.1	—	—	—	—	46.1
Write-off of excess tax benefits related to share-based compensation	—	(8.3)	—	—	—	—	(8.3)
Stock options exercised	—	0.5	—	—	—	—	0.5
Employee stock purchases	—	5.1	—	—	—	—	5.1
Employee stock grants	0.1	(0.1)	—	—	—	—	—
Repurchase of employee common stock relinquished for tax withholding	—	—	(2.4)	—	—	—	(2.4)
Distributions to noncontrolling interests	—	—	—	—	—	(4.7)	(4.7)
Dividend payable to noncontrolling interests	—	—	—	—	—	(42.5)	(42.5)
December 31, 2014	$2.9	$2,383.3	$(467.1)	$1,570.5	$ (764.8)	$ 1.7	$2,726.5

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (the Company) and its affiliates. Interests in subsidiaries controlled by the Company are consolidated with any outside shareholder interests reflected as noncontrolling interests, except when the Company has an undivided interest in an unincorporated joint venture. In those cases, the Company includes its proportionate share in the assets, liabilities, revenues and expenses of the jointly controlled entities within each applicable line item of the consolidated financial statements. All intercompany transactions, profits and balances have been eliminated in consolidation. Certain amounts from prior years have been reclassified to conform with the 2014 presentation.

Description of Business

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

Newly Adopted Accounting Standards

Presentation of Unrecognized Tax Benefits. In July 2013, the Financial Accounting Standards Board (FASB) issued accounting guidance requiring entities to present unrecognized tax benefits as a reduction to any related deferred tax assets for net operating losses, similar tax losses or tax credit carryforwards if such settlement is required or expected in the event an uncertain tax position is disallowed. Previously effective U.S. GAAP did not provide explicit guidance on the topic. The new presentation guidance became effective for interim and annual periods beginning after December 15, 2013 (January 1, 2014 for the Company). The adoption of the guidance beginning January 1, 2014 had no material effect on the Company's results of operations, financial condition, cash flows or financial statement presentation.

Accounting Standards Not Yet Implemented

Going Concern. In August 2014, the FASB issued disclosure guidance that requires management to evaluate, at each annual and interim reporting period, whether substantial doubt exists about an entity's ability to continue as a going concern and, if applicable, to provide related disclosures. As outlined by that guidance, substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that an entity will be unable to meet its obligations as they become due within one year after the date that the financial statements are issued (or are available to be issued). The new guidance will be effective for annual reporting periods ending after December 15, 2016 (the year ending December 31, 2016 for the Company) and interim periods thereafter, with early adoption permitted.

Revenue Recognition. In May 2014, the FASB issued a comprehensive revenue recognition standard that will supersede nearly all existing revenue recognition guidance under U.S. GAAP. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers, which steps are to (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when each performance obligation is satisfied. More specifically, revenue will be recognized when promised goods or services are transferred to the customer in an amount that reflects the consideration expected in exchange for those goods or services. The standard also requires entities to disclose sufficient qualitative and quantitative information to enable financial statement users to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The new guidance will be effective for interim and annual periods beginning after December 15, 2016 (January 1, 2017 for the Company) and the standard allows for either a full retrospective adoption or a modified retrospective adoption. The Company is in the process of evaluating the impact that the adoption of this guidance will have on its results of operations, financial condition, cash flows and financial statement presentation.

Discontinued Operations. In April 2014, the FASB issued accounting guidance that raised the threshold for disposals to qualify as discontinued operations to a disposal of a component or group of components that is disposed of or is classified as held for sale and represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results. Such a strategic shift may include the disposal of (1) a major geographical area of operations, (2) a major line of business, (3) a major equity method investment or (4) other major parts of an entity. Provided that the major strategic shift criterion is met, the new guidance does allow entities to have significant continuing involvement and continuing cash flows with the discontinued operation, unlike current U.S. GAAP. The new standard also requires additional disclosures for discontinued operations and new disclosures for individually material disposal transactions that do not meet the definition of a discontinued operation. The new guidance will apply prospectively to disposals that occur in interim and annual periods beginning on or after December 31, 2014 (January 1, 2015 for the Company). The impact to the Company's financial statements will depend on any disposal activity that occurs subsequent to adoption in 2015.

Sales

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

Other Revenues

"Other revenues" include net revenues from coal trading activities as discussed in Note 7. "Coal Trading," as well as coal sales revenues that were derived from the Company's mining operations and sold through the Company's coal trading business. Also included are revenues from contract termination or restructuring payments, royalties related to coal lease agreements, sales agency commissions, farm income, property and facility rentals and generation development activities. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced.

Discontinued Operations and Assets Held for Sale

The Company classifies items within discontinued operations in the consolidated financial statements when the operations and cash flows of a particular component of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal (by sale or otherwise) and the Company will no longer have any significant continuing involvement in the operation of that component. Refer to Note 3. "Discontinued Operations" for additional details related to discontinued operations.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with original maturities of three months or less.

Inventories

Coal is reported as inventory at the point in time the coal is extracted from the mine. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Saleable coal represents coal stockpiles which require no further processing prior to shipment to a customer.

Coal inventory is valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment (including depreciation thereto) and operating overhead and other related costs incurred at or on behalf of the mining location. Market represents the estimated net realizable value of the inventory, which considers the projected future sales price of the particular coal product, less applicable selling costs, and, in the case of raw coal, estimated remaining processing costs. The valuation of coal inventory is subject to several additional estimates, including those related to ground and aerial surveys used to measure quantities and processing recovery rates.

Materials and supplies inventory is valued at the lower of average cost or market, less a reserve for obsolete or surplus items. This reserve incorporates several factors, such as anticipated usage, inventory turnover and inventory levels.

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

Investments in Marketable Securities
The Company’s short-term investments in marketable securities, which are included in "Other current assets" in the consolidated balance sheets, are defined as those investments with original maturities upon purchase of greater than three months and up to one year. Long-term investments, which are included in "Investments and other assets" in the consolidated balance sheets, are defined as those investments with original maturities upon purchase of greater than one year.
The Company classifies its investments in debt securities as either held-to-maturity or available-for-sale at the time of purchase and reevaluates such designation periodically. Such investments are classified as held-to-maturity when the Company has the intent and ability to hold the securities to maturity. Investments in debt securities not classified as held-to-maturity and investments in marketable equity securities are classified as available-for-sale. Available-for-sale securities are carried at fair value, with unrealized gains and losses, net of income taxes, generally reported in “Accumulated other comprehensive loss” in the consolidated balance sheets. Realized gains and losses, determined on a specific identification method, are included in “Interest income” in the consolidated statements of operations.
At each reporting date, the Company performs separate evaluations of its marketable securities to determine if any unrealized losses present are other-than-temporary. Such evaluations involve the consideration of several factors, including, but not limited to, the length of time the market value has been less than cost, the financial condition and near-term prospects of the issuer of the securities and whether the Company has the positive intent and ability to hold the securities until recovery. Refer to Note 2. "Asset Impairment and Mine Closure Costs" and Note 5. "Investments" for details regarding other-than-temporary impairment losses of $4.7 million, $21.5 million and $35.5 million recognized during the years ended December 31, 2014, 2013 and 2012, respectively, related to the Company's marketable equity securities holdings.
Property, Plant, Equipment and Mine Development
Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Capitalized interest in 2014, 2013 and 2012 was immaterial. Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Costs incurred to maintain current production capacity at a mine are charged to operating costs as incurred. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.
Coal reserves are recorded at cost, or at fair value in the case of nonmonetary exchanges, of reserves or business acquisitions.
Depletion of coal reserves and amortization of advance royalties is computed using the units-of-production method utilizing only proven and probable reserves (as adjusted for recoverability factors) in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method. Depreciation of plant and equipment is computed using the straight-line method over the shorter of the asset's estimated useful life or the life of the mine. The estimated useful lives by category of assets are as follows:

	Years
Building and improvements	1 to 37
Machinery and equipment	1 to 37
Leasehold improvements	Shorter of Useful Life or Remaining Life of Lease

Equity and Cost Method Investments
The Company accounts for its investments in less than majority owned corporate joint ventures under either the equity or cost method. The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost and any difference between the cost of the Company’s investment

and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company’s pro-rata share of the operating results of joint ventures and basis difference amortization is reported in the consolidated statements of operations in “Loss from equity affiliates.” Similarly, the Company's pro-rata share of the cumulative foreign currency translation adjustment of its equity method investments whose functional currency is not the U.S. dollar is reported in the consolidated balance sheet as a component of "Accumulated other comprehensive loss," with periodic changes thereto reflected in the consolidated statements of comprehensive income.

The Company monitors its equity and cost method investments for indicators that a decrease in investment value has occurred that is other than temporary. Examples of such indicators include a sustained history of operating losses and adverse changes in earnings and cash flow outlook. In the absence of quoted market prices for an investment, discounted cash flow projections are used to assess fair value, the underlying assumptions to which are generally considered unobservable Level 3 inputs under the fair value hierarchy. If the fair value of an investment is determined to be below its carrying value and that loss in fair value is deemed other than temporary, an impairment loss is recognized. No such impairment losses were recorded during the year ended December 31, 2014. Refer to Note 2. "Asset Impairment and Mine Closure Costs" and Note 5. "Investments" for details regarding other-than-temporary impairment losses of $43.2 million and $39.4 million recorded during the years ended December 31, 2013 and 2012, respectively, related to certain of the Company's equity and cost method investments.

Asset Retirement Obligations

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

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

Contingent Liabilities

From time to time, the Company is subject to legal and environmental matters related to our continuing and discontinued operations and certain historical, non-coal producing operations. In connection with such matters, the Company is required to assess the likelihood of any adverse judgments or outcomes, as well as potential ranges of probable losses.

A determination of the amount of reserves required for these matters is made after considerable analysis of each individual issue. The Company accrues for legal and environmental matters within "Operating costs and expenses" when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company provides disclosure surrounding loss contingencies when it believes that it is at least reasonably possible that a material loss may be incurred or an exposure to loss in excess of amounts already accrued may exist. Adjustments to contingent liabilities are made when additional information becomes available that affects the amount of estimated loss, which information may include changes in facts and circumstances, changes in interpretations of law in the relevant courts, the results of new or updated environmental remediation cost studies and the ongoing consideration of trends in environmental remediation costs.

Accrued contingent liabilities exclude claims against third parties and are not discounted. The current portion of these accruals is included in “Accounts payables and accrued expenses” and the long-term portion is included in “Other noncurrent liabilities” in the consolidated balance sheets. In general, legal fees related to environmental remediation and litigation are charged to expense. The Company includes the interest component of any litigation-related penalties within "Interest expense" in the consolidated statements of operations.

Income Taxes

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

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

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions by accruing the costs of benefits to be provided over the employees’ period of active service. These costs are determined on an actuarial basis. The Company’s consolidated balance sheets reflect the accumulated postretirement benefit obligations of its postretirement benefit plans. The Company accounts for changes in its postretirement benefit obligations as a settlement when an irrevocable action has been effected that relieves the Company of its actuarially-determined liability to individual plan participants and removes substantial risk surrounding the nature, amount and timing of the obligation’s funding and the assets used to effect the settlement. See Note 15. "Postretirement Health Care and Life Insurance Benefits" for information related to postretirement benefits.

Pension Plans

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

Restructuring Activities

From time to time, the Company initiates restructuring activities in connection with its repositioning efforts to appropriately align its cost structure or optimize its coal production relative to prevailing global coal industry conditions. Costs associated with restructuring actions can include early mine closures, voluntary and involuntary workforce reductions, office closures and other related activities. Costs associated with restructuring activities are recognized in the period incurred.

Included as a component of "Restructuring and pension settlement charges" in the the Company's consolidated statements of operations for the years ended December 31, 2014 and 2013 were aggregate restructuring charges of $15.7 million and $11.9 million, respectively, primarily associated with voluntary and involuntary workforce reductions. The majority of the cash expenditures associated with the charges recognized in 2014 are expected to be paid in the first quarter of 2015.

In 2013, the Company ceased production and commenced with the early closure of the Wilkie Creek Mine in the Surat Basin in Queensland, Australia. In 2012, we initiated two early mine closures in the U.S.: the Air Quality Mine in Indiana and Willow Lake Mine in Illinois. See Note 2. "Asset Impairment and Mine Closure Costs" and Note 3. "Discontinued Operations" for information related to those early mine closures. No mines were closed in advance of the anticipated exhaustion of reserves in 2014.

Derivatives

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

With respect to derivatives used in hedging activities, the Company assesses, both at inception and at least quarterly thereafter, whether such derivatives are highly effective at offsetting the changes in the anticipated exposure of the hedged item. The effective portion of the change in the fair value of derivatives designated as a cash flow hedge is recorded in “Accumulated other comprehensive loss” until the hedged transaction impacts reported earnings, at which time any gain or loss is reclassified to earnings. To the extent that periodic changes in the fair value of derivatives deemed highly effective exceeds such changes in the hedged item, the ineffective portion of the periodic non-cash changes are recorded in earnings in the period of the change. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes changes in the fair value of the instrument in earnings in the period of the change. The potential for hedge ineffectiveness is present in the design of certain of the Company’s cash flow hedge relationships and is discussed in detail in Note 6. "Derivatives and Fair Value Measurements" and Note 7. "Coal Trading." Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in earnings, along with the offsetting gain or loss related to the underlying hedged item.

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

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

Business Combinations

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

Impairment of Long-Lived Assets

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

Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. For its active mining operations, the Company generally groups such assets at the mine level, or the mining complex level for mines that share infrastructure, with the exception of impairment evaluations triggered by mine closures. In those cases involving mine closures, the related assets are evaluated at the individual asset level for remaining economic life based on transferability to ongoing operating sites and for use in reclamation-related activities, or for expected salvage. For its development and exploration properties and portfolio of surface land and coal reserve holdings, the Company considers several factors to determine whether to evaluate those assets individually or on a grouped basis for purposes of impairment testing. Such factors include geographic proximity to one another, the expectation of shared infrastructure upon development based on future mining plans and whether it would be most advantageous to bundle such assets in the event of sale to a third party.

When indicators of impairment are present, the Company evaluates its long-lived assets for recoverability by comparing the estimated undiscounted cash flows expected to be generated by those assets under various assumptions to their carrying amounts. If such undiscounted cash flows indicate that the carrying value of the asset group is not recoverable, impairment losses are measured by comparing the estimated fair value of the asset group to its carrying amount. As quoted market prices are unavailable for the Company's individual mining operations, fair value is determined through the use of an expected present value technique based on the income approach, except for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from the Company's long-range mine planning. In those cases, a market approach is utilized based on the most comparable market multiples available. The estimated future cash flows and underlying assumptions used to assess recoverability and, if necessary, measure the fair value of the Company's long-lived mining assets are derived from those developed in connection with the Company's planning and budgeting process. The Company believes its assumptions to be consistent with those a market participant would use for valuation purposes. The most critical assumptions underlying the Company's

projections and fair value estimates include those surrounding future tons sold, coal prices for unpriced coal, production costs (including costs for labor, commodity supplies and contractors), transportation costs, foreign currency exchange rates and a risk-adjusted, after-tax cost of capital (all of which generally constitute unobservable Level 3 inputs under the fair value hierarchy), in addition to market multiples for non-strategic coal reserves, surface lands and undeveloped coal properties excluded from the Company's long-range mine planning (which generally constitute Level 2 inputs under the fair value hierarchy).
Refer to Note 2. "Asset Impairment and Mine Closure Costs" for details regarding impairment charges related to long-lived assets of $149.7 million, $463.6 million and $833.6 million recognized during the years ended December 31, 2014, 2013 and 2012, respectively.

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Fair Value

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

Foreign Currency

Functional currency is determined by the primary economic environment in which an entity operates, which for the Company's foreign operations is generally the U.S. dollar because sales prices in international coal markets and the Company's sources of financing those operations is denominated in that currency. Accordingly, substantially all of the Company’s consolidated foreign subsidiaries utilize the U.S. dollar as their functional currency. Monetary assets and liabilities are remeasured at year-end exchange rates while non-monetary items are remeasured at historical rates. Income and expense accounts are remeasured at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement related to tax balances are included as a component of "Income tax (benefit) provision," while all other remeasurement gains and losses are included in "Operating costs and expenses." The total impact of foreign currency remeasurement on the consolidated statements of operations was a net loss of $1.3 million for the year ended December 31, 2014 and a net gain of $34.1 million and $4.8 million for the years ended December 31, 2013 and 2012, respectively.

The Company owns a 50% equity interest Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. Middlemount utilizes the Australian dollar as its functional currency. Accordingly, the assets and liabilities of that equity investee are translated to U.S. dollars at the year-end exchange rate and income and expense accounts are translated at the average rate in effect during the year. The Company's pro-rata share of the translation gains and losses of the equity investee are recorded as a component of "Accumulated other comprehensive loss." Australian dollar denominated shareholder loans to the Middlemount Mine, which are long term in nature, are considered part of the Company's net investment in that operation. Accordingly, foreign currency gains or losses on those loans are recorded as a component of foreign currency translation adjustment. The Company recorded foreign currency translation losses of $41.0 million and $92.7 million for the years ended December 31, 2014 and 2013, respectively, and a translation gain of $19.1 million for the year ended December 31, 2012.

Share-Based Compensation

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

Exploration and Drilling Costs

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

Advance Stripping Costs

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

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

Use of Estimates in the Preparation of the Consolidated Financial Statements

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

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(2) Asset Impairment and Mine Closure Costs

Year Ended December 31, 2014

The following costs are reflected in "Asset impairment and mine closure costs" in the consolidated statement of operations for the year ended December 31, 2014:

	Reportable Segment			
	Australian Mining	Western U.S. Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Asset impairment charges:				
Long-lived assets	$78.6	$2.7	$68.4	$149.7
Marketable securities	—	—	4.7	4.7
Total	$78.6	$2.7	$73.1	$154.4

Long-Lived Assets

Australian Mining. In 2014, the Company observed continued weakness in seaborne metallurgical and thermal coal pricing that has persisted longer than the Company previously anticipated and, accordingly, conducted a review of its Australian Mining segment assets for recoverability. Based on that evaluation, the Company determined that the carrying values of one of its active surface mines that produces metallurgical and thermal coal and two non-strategic undeveloped coal properties were not recoverable and correspondingly recognized an aggregate impairment charge of $78.6 million to write those assets down from their carrying value to their estimated fair value. In addition to the impairment indicators surrounding the Australian Mining segment as a whole, the fair value of the impaired surface mining operation was affected by a short remaining economic life compared to those of other operations and the incremental cost associated with utilizing a contractor to operate the mine.

Corporate and Other. The Company identified indicators of impairment to be present in 2014 for certain of its non-strategic undeveloped coal properties in Indiana and Colorado due to a lack of observed interest from potential buyers in acquiring those assets, properties that are no longer part of the Company's long-term mining plan and, in the case of certain of the assets, an election by the Company to terminate or allow the lapse of mining-related leases. The Company determined the carrying value of those holdings to not be recoverable and recognized an aggregate impairment charge of $68.4 million to write down the carrying value of the related properties.

Marketable Securities

Refer to Note 5. "Investments" for additional details surrounding an other-than-temporary impairment charge of $4.7 million recorded during the fourth quarter of 2014 related to the Company's investment in the marketable equity securities of Winsway Enterprises Holdings Limited (Winsway), formally referred to as Winsway Coking Coal Holdings Limited.

Risks and Uncertainties

The Company's mining and exploration assets and mining-related investments may be adversely affected by numerous uncertain factors that may cause the Company to be unable to recover all or a portion of the carrying value of those assets. The Company generally does not view short-term declines in thermal and metallurgical coal prices in the markets in which it sells its products as an indicator of impairment. However, the Company generally does view a sustained trend (for example, over periods exceeding one year) of adverse coal market pricing or unfavorable changes thereto as a potential indicator of impairment. Because of the volatile and cyclical nature of U.S. and international seaborne coal markets, it is reasonably possible that prices in those market segments may decrease and/or fail to improve in the near term, which may result in the need for future adjustments to the carrying value of the Company's long-lived mining assets and mining-related investments.

The Company's assets whose recoverability and values are most sensitive to near-term pricing include certain non-strategic Australian undeveloped coal properties and mining-related investments. Such assets had an aggregate carrying value of $124.1 million as of December 31, 2014. The Company conducted a review of those assets for recoverability as of December 31, 2014 and determined that, other than the charges related to the Australian Mining segment described above, no further impairment charge was necessary as of that date.

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

Year Ended December 31, 2013
The following costs are reflected in "Asset impairment and mine closure costs" in the consolidated statement of operations for the year ended December 31, 2013:

	Reportable Segment		
	Australian Mining	Corporate and Other	Consolidated
	(Dollars in millions)		
Asset impairment charges:			
Long-lived assets	$390.8	$72.8	$463.6
Equity method investment	—	43.2	43.2
Marketable securities	—	21.5	21.5
Total	$390.8	$137.5	$528.3

Long-Lived Assets
Australian Mining. In 2013, the Company determined that the long-lived assets of one of its active surface mines that produces metallurgical and thermal coal, one of its surface mining development projects that the Company instead decided to pursue as an underground operation and an exploration tenement were not recoverable, in whole or in part, and correspondingly recognized an aggregate impairment charge of $390.8 million to write each of those assets down from its carrying value to its estimated fair value. In addition to weakness in seaborne metallurgical and thermal coal pricing, the fair value of the impaired surface mining operation was affected by a short remaining economic life compared to those of other operations and site-specific adverse changes in 2013 surrounding realized coal quality yields, contractor performance and contract mining terms, the latter of which were amended during the fourth quarter of that period. With respect to the exploration tenement, the Company determined the fair value of that asset based on an indicative sale offer received in December 2013, which constituted a Level 2 input under the fair value hierarchy. That sale was executed in January 2014, as described further in Note 20. "Resource Management and Other Commercial Events."
Corporate and Other. In December 2013, contract mining at a coal reserve property in the Eastern U.S. substantially ended upon completion of mining within the existing permit area and new permits were not obtained for the remaining reserves at that property due to new permitting conditions that the Company deemed unacceptable and projected poor near-term economic performance. As a result of that decision and a lack of observed interest from certain financial and strategic buyers in acquiring the remaining coal reserves, the Company recorded an impairment charge of $66.3 million to write down the carrying value of the related reserves. Also, in connection with a review of its portfolio of surface land and coal reserve holdings, the Company determined the carrying value of one of its coal reserve holdings leased to a third-party underground miner to not be fully recoverable and recognized an impairment charge of $6.5 million to write down the carrying value of those reserves to their estimated fair value.
Mine Closures
Wilkie Creek Mine. In December 2013, the Company approved a decision to cease production at the Wilkie Creek Mine in the Surat Basin in Queensland, Australia, and commenced with the closure of that mine. The results of that mine are reported as a discontinued operation for all periods presented because the operations and cash flows of the mine have been eliminated from the ongoing operations of the Company as a result of its closure. Refer to Note 3. "Discontinued Operations" for additional details regarding charges recognized during the year ended December 31, 2013 related to this mine closure.
Equity Method Investment
Refer to Note 5. "Investments" for additional details surrounding an other-than-temporary impairment charge of $43.2 million recognized in 2013 associated with the Company's 50% equity interest in Middlemount.
Marketable Securities

Refer to Note 5. "Investments" for additional details surrounding an other-than-temporary impairment charge of $21.5 million recorded during the second quarter of 2013 related to the Company's investment in Winsway marketable equity securities.

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

Year Ended December 31, 2012

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

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