PEABODY ENERGY CORP
Form 10-K
March 16, 2016
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, 2015
or
o 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 o No þ

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 o 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 o

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 o

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 o	Non-accelerated filer o	Smaller reporting company o

(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 o 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, 2015: Common Stock, par value $0.01 per share, $606.1 million.

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of March 8, 2016: Common Stock, par value $0.01 per share, 18,538,665 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 2016 Annual Meeting of Shareholders (the Company's 2016 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

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

Without limiting the foregoing, all statements relating to our future operating results, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements and speak only as of the date of this report. These forward-looking statements are based on numerous assumptions that we believe are reasonable, but are subject to a wide range of uncertainties and business risks and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ materially are:

- supply and demand for our coal products;
- sustained depressed levels or further declines in coal prices;
- competition in coal markets;
- price volatility, particularly in international seaborne products and in our trading and brokerage businesses;
- adequate liquidity to operate our business and service our debt obligations;
- impacts of our high leverage and our ability to comply with the covenants in our credit agreements, particularly our leverage ratio and interest coverage covenants;
- our ability to successfully negotiate transactions with debt holders, including debt exchanges and debt buybacks;
- our ability to successfully consummate the planned sale of our assets in New Mexico and Colorado, including the purchaser's ability to successfully obtain financing, and the divestiture of our interest in the Prairie State Energy Campus;
- the cost, availability and access to capital and financial markets, including the ability to secure new financing;
- ability to appropriately secure our obligations for reclamation, federal and state workers' compensation, federal coal leases and other obligations related to our operations, including our ability to remain eligible for self-bonding and/ or successfully access the commercial surety bond market;
- customer procurement practices and contract duration;
- impact of alternative energy sources, including natural gas and renewables;
- global steel demand and the downstream impact on metallurgical coal prices;
- lower demand for our products by electric power generators;
- impact of weather and natural disasters on demand, production and transportation;
- reductions and/or deferrals of purchases by major customers and our 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, including, without limitation, the actions we are implementing to improve our organization and respond to current market conditions;
- negotiation of labor contracts, employee relations and workforce availability, including, without limitation, attracting and retaining key personnel;
- changes in postretirement benefit and pension obligations and their related funding requirements;
- replacement and development of coal reserves;
- impacts of our high leverage and our ability to comply with the covenants in our credit agreements, particularly our leverage ratio and interest coverage covenants;
- 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 laws, regulations or requirements, changes in income tax regulations, sales-related royalties or other regulatory taxes and changes in derivatives laws and regulations;
- our ability to obtain and renew permits necessary for our operations;
- litigation or other dispute resolution, including, but not limited to, claims not yet asserted;
- any additional liabilities or obligations that we may have as a result of the bankruptcy of Patriot Coal Corporation (Patriot), including, without limitation, as a result of litigation filed by third parties in relation to that bankruptcy;
- terrorist attacks or security threats, including, but not limited to, 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 (by volume). As of December 31, 2015, 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, the United Kingdom and the U.S. (listed alphabetically).

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 2015, we achieved a record global safety performance for us, and we advanced operational and capital projects focused on operational efficiency and maintaining a competitive position in the market segments in which we operate. Such advancements included advancing the development at the planned Gateway North Mine in the U.S. to replace production from the existing Gateway Mine as its reserves were exhausted in the second half of 2015 and continuing our ongoing cost containment initiatives across our global platform in response to challenged global coal market segment conditions.

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Segment and Geographic Information

During the second quarter of 2015, we elected a new chief executive officer, who is also considered our chief operating decision maker (CODM). Due to that change, we updated our reportable segments to reflect the manner in which our new CODM views our businesses for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. We now report our results of operations primarily through the following reportable segments: "Powder River Basin Mining," "Midwestern U.S. Mining," "Western U.S. Mining," "Australian Metallurgical Mining," "Australian Thermal Mining," "Trading and Brokerage" and "Corporate and Other."

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

U.S. Mining Operations

The principal business of our mining segments in the U.S. is the mining, preparation and sale of thermal coal, sold primarily to electric utilities in the U.S. under long-term contracts, with a portion sold into the seaborne markets as market conditions warrant. Our Powder River Basin Mining operations consist of our mines in Wyoming. The mines in that segment are characterized by surface mining extraction processes, coal with a lower sulfur content and Btu and higher customer transportation costs (due to longer shipping distances). Our Midwestern U.S. Mining operations include our Illinois and Indiana mining operations, which are characterized by a mix of surface and underground mining extraction processes, coal with a higher Btu and sulfur content and lower customer transportation costs (due to shorter shipping distances). Our Western U.S. Mining operations reflect the aggregation of our New Mexico, Arizona and Colorado mining operations. The mines in that segment are characterized by a mix of surface and underground mining extraction processes, and of coal with mid-range sulfur and Btu content. Geologically, our Powder River Basin Mining operations mine sub-bituminous coal deposits, our Midwestern U.S. Mining operations mine bituminous coal deposits and our Western operations mine both bituminous and sub-bituminous coal deposits.

Australian Mining Operations

The business of our Australian operating platform is primarily export focused with customers spread across several countries, while a portion of our thermal coal is sold within Australia. Generally, revenues from individual countries vary year by year based on electricity and steel demand, the strength of the global economy, governmental policies and several other factors, including those specific to each country. Our Australian Metallurgical Mining operations consist of mines in Queensland and one in New South Wales, Australia. The mines in that segment are characterized by both surface and underground extraction processes used to mine various qualities of metallurgical coal (low-sulfur, high Btu coal). The metallurgical coal qualities include hard coking coal, semi-hard coking coal, semi-soft coal and pulverized coal injection (PCI) coal. Our Australian Thermal Mining operations consist of mines in New South Wales, Australia. The mines in that segment are characterized by both surface and underground extraction processes used to mine low-sulfur, high Btu thermal coal. We classify our Australian mines within the Australian Metallurgical Mining or Australian Thermal Mining segments based on the primary customer base and coal reserve type of each mining operation. A small portion of the coal mined by the Australian Metallurgical Mining segment is of a thermal grade. Similarly, a small portion of the coal mined by the Australian Thermal Mining segment is of a metallurgical grade. Additionally, the Company may market some of its metallurgical coal products as a thermal coal product from time to time depending on market conditions.

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The table below summarizes information regarding the operating characteristics of each of our mines that were active in 2015 in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2015.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Primary Transport Method	2015 Tons Sold (In millions)
Powder River Basin Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	109.3
Rawhide	Wyoming	S	D, T/S	T	R	15.2
Caballo	Wyoming	S	D, T/S	T	R	11.4
Other (1)	—	—	—	—	—	2.9
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	Tr, R	7.9
Francisco Underground	Indiana	U	CM	T	R	2.9
Somerville Central	Indiana	S	DL, D, T/S	T	R, R/B, T/B, T/R	2.1
Wild Boar	Indiana	S	D, T/S	T	Tr, R, R/B, T/B	2.0
Wildcat Hills Underground	Illinois	U	CM	T	T/B	1.7
Gateway (2)	Illinois	U	CM	T	Tr, R, R/B, T/B	1.3
Cottage Grove	Illinois	S	D, T/S	T	T/B	1.3
Somerville North	Indiana	S	D, T/S	T	Tr, R, R/B, T/B, T/R	0.8
Somerville South	Indiana	S	D, T/S	T	Tr, R, R/B, T/B,	0.7
Gateway North	Illinois	U	CM	T	Tr, R, R/B, T/B	0.5
Western U.S. Mining						
El Segundo	New Mexico	S	D, DL, T/S	T	R	8.1
Kayenta	Arizona	S	DL, T/S	T	R	6.6
Twentymile	Colorado	U	LW	T	R, Tr	3.2
Lee Ranch	New Mexico	S	T/S	T	R	—
Australian Metallurgical Mining						
Millennium	Queensland	S	D, T/S	M, P	R, EV	4.6
Coppabella (3)	Queensland	S	DL, D, T/S	P	R, EV	2.9
North Goonyella	Queensland	U	LTCC	M	R, EV	2.7
Moorvale (3)	Queensland	S	T/S	P	R, EV	2.3
Metropolitan	New South Wales	U	LW	M	R, EV	2.0
Burton *	Queensland	S	T/S	M, T	R, EV	1.2
Middlemount (4)	Queensland	S	T/S	M, P	R, EV	—
Australian Thermal Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	13.5
Wambo Open-Cut (5)	New South Wales	S	T/S	T	R, EV	3.5
North Wambo Underground (5)	New South Wales	U	LW	M, T	R, EV	3.1

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 Powder River Basin Mining primarily consists of purchased coal used to satisfy certain specific coal supply agreements.

(2) Mine ceased production in 2015 due to exhaustion of reserves.

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

(4) 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, 2015 tons sold from that mine, which totaled 4.2 million tons (on a 100% basis), have been excluded from the table above.

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

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.

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Trading and Brokerage Segment

Our Trading and Brokerage segment engages in the direct and brokered trading of coal and freight-related contracts through our trading and business offices. 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. The 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, from time to time, cash flow hedging in support of our coal trading strategy.

Corporate and Other Segment

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

Resource Management. As of December 31, 2015, we held approximately 6.3 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 2015. During the years ended December 31, 2015, 2014 and 2013, the mine sold 4.2 million, 3.7 million and 2.8 million tons of coal, respectively (on a 100% basis).

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 own a 5.06% participating interest 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 pro rata portion of Prairie State's production costs and marketing and selling our share of electricity generated by the facility. In January 2016, we entered into a definitive agreement to sell our subsidiary holding this participating interest in the Prairie State Energy Campus to the Wabash Valley Power Association for approximately $57 million, subject to certain customary closing adjustments and satisfaction of closing conditions.

Clean Coal Technology. We continue to support clean coal technology development and initiatives seeking to be more energy efficient and 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 continued to support the development of the FutureGen 2.0 project until the Department of Energy funding was terminated in 2015. 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. During 2015, Peabody acknowledged the lowest SO_2, NO_X and CO_2 emitting coal plants globally and in India, Europe, Asia (excluding China) and the U.S.

through our Advanced Energy for Life Clean Coal Awards.

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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 88%, 83% and 80% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2015, 2014 and 2013, respectively.

For the year ended December 31, 2015, we derived 26% of our total revenues from our five largest customers. Those five customers were supplied primarily from 31 coal supply agreements (excluding trading transactions) expiring at various times from 2016 to 2026. The contract contributing the greatest amount of annual revenue in 2015 was approximately $285 million, or approximately 5% of our 2015 total revenues, and is due to expire in 2026.

Backlog. Our sales backlog (excluding trading transactions), which includes coal supply agreements subject to price reopener and/or extension provisions, was approximately 690 million and 800 million tons of coal as of January 1, 2016 and 2015, respectively. Contracts in backlog have remaining terms ranging from one to 12 years and represent approximately three years of production based on our 2015 production volume of 208.7 million tons. Approximately 74% of our backlog is expected to be filled beyond 2016.

U.S. Mining Operations. Revenues from our Powder River Basin Mining, Western U.S. Mining and Midwestern U.S. Mining segments, in aggregate, represented approximately 63%, 59% and 57% of our total revenue base for the years ended December 31, 2015, 2014 and 2013, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 83%, 83% and 84% of our sales volumes from mining operations. We expect to continue selling a significant portion of our Powder River Basin Mining, 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 approach 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 Metallurgical Mining and Australian Thermal Mining segments represented approximately 36%, 39% and 41% of our total revenue base for the years ended December 31, 2015, 2014 and 2013, respectively, during which periods the coal mining activities of those segments contributed respective amounts of 17%, 17% and 16% 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 and priced on a shorter-term basis. The portion of volume priced on a shorter-term basis 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, and we pay 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).

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 4 in the foregoing "Mining Segments" section for a summary of transportation methods by mine.

Export Facilities. Our U.S. Mining operations exported 0%, 1% and 2% of its annual tons sold for the years ended December 31, 2015, 2014 and 2013, respectively. The 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 periodically 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%, 77% and 75% of its tons into the seaborne coal markets for the years ended December 31, 2015, 2014 and 2013, respectively. We have generally secured our ability to transport coal in Australia through rail and port contracts and interests in five 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 have undue operational or financial risk associated with our dependence on any 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, continuous improvement 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.

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 and in 2015, working with the manufacturer, have improved the design of the equipment to improve safety of the system for future longwall panels.

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.

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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.

During 2015, Peabody has expanded several innovative programs to enhance safety and reduce costs, including;

- The use of unmanned drones for aerial pit and stockpile surveys and plan to use them for inspection of equipment (dragline booms) that cannot easily be accessed;
- Began testing of autonomous blast hole drills;
- Expanded the utilization of remote equipment health monitoring to several mines and established a regional monitoring center in Brisbane; and
- Enhanced real time monitoring of prep plants through the installation of the AMPLA product at several sites.

Competition

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 cost of alternative fuels, the impact of weather on heating and cooling demand and taxes and environmental regulations imposed by the U.S. and foreign governments.

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, also 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 energy cost (including transportation costs), customer service and support and reliability of supply.

The use of thermal coal is heavily 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. Alternative fuels to thermal coal include natural gas, fuel oil, 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 2016 “Short Term Energy Outlook” that coal’s share of U.S. electricity generation for all sectors was 33% in 2015, down from 39% in 2014. Electricity generation from coal was negatively impacted by a 40% decline in average U.S. natural gas prices, which fell to an average price of $2.63 per mmBtu in 2015. The EIA expects full year average U.S. natural gas prices to remain in line with 2015 prices at an average of $2.64 per mmBTU.

Our principal U.S. direct coal supply 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., which collectively accounted for approximately 37% of total U.S. coal production in 2014 according to the National Mining Association's "2014 Coal Producer Survey," the most recent data publicly available as of March 15, 2016. 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.

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), which was fully drawn in February 2016 as a means to provide us with the maximum amount of control and flexibility with respect to our liquidity position, and our accounts receivable securitization program, which expires in April 2016, are also available to fund our working capital requirements. The Company has started the process of renewing the Accounts Receivable Securitization program. 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 7,600 employees as of December 31, 2015, including approximately 5,700 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)]
Glenn L. Kellow	48	President and Chief Executive Officer
Amy B. Schwetz	41	Executive Vice President and Chief Financial Officer
Bryan A. Galli	55	Group Executive of Marketing and Trading
Christopher J. Hagedorn	43	Group Executive of Strategy and Development
Charles F. Meintjes	53	President - Australia
A. Verona Dorch	48	Executive Vice President, Chief Legal Officer, Government Affairs and Corporate Secretary
Andrew P. Slentz	54	Executive Vice President Human Resources and Administration
Kemal Williamson	56	President - Americas

(1) As of March 8, 2016.

Glenn L. Kellow was named our President and Chief Operating Officer in August 2013, our President, Chief Executive Officer-elect and a director in January 2015 and our President and Chief Executive Officer in May 2015. 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 director and executive committee member of the World Coal Association, the U.S. National Mining Association and the International Energy Agency Coal Industry Advisory Board. He is the former Chairman of Worsley Alumina in Australia, Chairman of Mozal in Mozambique, and Chairman of the global Nickel Institute. In addition, he is 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 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.

Amy B. Schwetz was named our Executive Vice President and Chief Financial Officer in July 2015. Ms. Schwetz serves as our principal accounting officer. She has previously served as our Senior Vice President of Finance and Administration - Australia, from June 2013 to June 2015; Senior Vice President of Finance and Administration - Americas, from March 2012 to June 2013; Vice President of Investor Relations, from December 2011 to March 2012; Vice President of Capital and Financial Planning, from November 2009 to December 2011; Director of Financial Planning, from August 2007 to October 2009; and Director of Compliance and Accounting Policies, from August 2005 to August 2007. Prior to joining us, Ms. Schwetz was employed by Ernst & Young LLP, an international accounting firm, where she held multiple audit roles over eight years. She holds a bachelor's degree in Accounting from Indiana University, and is a Certified Public Accountant.

Bryan A. Galli was named our Group Executive of Marketing and Trading 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. Mr. Galli has held a variety of roles at Peabody since 2002. 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.

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Christopher J. Hagedorn was named our Group Executive of Strategy and Development 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.

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.

A. Verona Dorch was named our Executive Vice President, Chief Legal Officer, Governmental Affairs and Corporate Secretary in August 2015. She has executive responsibility for providing comprehensive legal counsel for Peabody business activities and leads the company's global legal compliance and government affairs functions. From July 2006 to March 2015, she served in a variety of roles at Harsco Corporation, a diversified, worldwide industrial services company, most recently serving as its Chief Legal Officer and Chief Compliance Officer. Ms. Dorch also has experience in corporate and securities law from top-tier law firms and with the Sumitomo Chemical Co. Ms. Dorch holds a bachelor's degree from Dartmouth College and a Juris Doctor degree from Harvard Law School.

Andrew P. Slentz was named our Executive Vice President Human Resources and Administration 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, which includes overseeing 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.

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Regulatory Matters — U.S.

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

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

Mine Safety and Health

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

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

MSHA has taken a number of actions to identify mines with safety issues, and has engaged in a number of targeted enforcement, awareness, outreach and rulemaking activities to reduce the number of mining fatalities, accidents and illnesses. There has also been an industry-wide increase in the monetary penalties assessed for citations of a similar nature.

In Part I, Item 4. "Mine Safety Disclosures" and in Exhibit 95 to this Annual Report on Form 10-K, we provide additional details on how we monitor safety performance and MSHA compliance, as well as provide the mine safety disclosures required by SEC regulations.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees and last worked for the operator after July 1, 1973. Coal mine operators must also make payments to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. Historically, less than 7% of the miners currently seeking federal black lung benefits are awarded these benefits; 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 impact our customers.

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

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

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

The SMCRA Abandoned Mine Land Fund requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund created by the Coal Industry Retiree Health Benefit Act of 1992. The fee amount can change periodically. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 to September 30, 2012, the fee was $0.315 and $0.135 per ton of surface-mined and underground-mined coal, respectively. From October 1, 2012 through September 30, 2021, the fee is $0.28 and $0.12 per ton of surface-mined and underground-mined coal, respectively.

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.

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. On October 1, 2015, the EPA issued a final rule setting the ozone standard at 70 parts per billion (ppb). 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, including the 2015 ozone standard, 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, modified and reconstructed 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. 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 and the NODA closed on May 9, 2014. The EPA released the final rule on August 3, 2015, and published it in the Federal Register on October 23, 2015.

The final rule requires that newly-constructed fossil fuel-fired steam generating units achieve an emission standard for carbon dioxide of 1,400 lb CO_2/MWh-gross. The standard is based on the performance of a supercritical pulverized coal boiler implementing partial carbon capture and storage (CCS). Modified and reconstructed fossil fuel fired steam generating units must implement the most efficient generation achievable through a combination of best operating practices and equipment upgrades, to meet an emission standard consistent with best historical performance. Reconstructed units must implement the most efficient generating technology based on the size of the unit (supercritical steam conditions for larger units, to meet a standard of 1,800 lb CO_2/MWh-gross, and subcritical conditions for smaller units to meet a standard of 2,000 lb CO_2/MWh-gross.).

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Numerous legal challenges to the final rule have been filed in the United States Court of Appeals (D.C. Circuit). Sixteen separate petitions for review were filed, and the challengers include 25 states, utilities, mining companies (including Peabody Energy), labor unions, trade organizations and other groups. The cases have been consolidated under the case filed by North Dakota. States and other organizations have intervened on behalf of the EPA. A briefing and argument schedule has not been set by the Court.

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. On August 3, 2015, the EPA announced the final rule, and published the rule in the Federal Register on October 23, 2015. In the final rule, the EPA is establishing final emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel-fired EGUs. These final guidelines require that the states individually or collectively create systems that would reduce carbon emissions from any EGU located within their borders. Individual states are required to submit their proposed implementation plans to the EPA by September 6, 2016, unless an extension is approved, in which case the states will have until September 6, 2018. The rule sets emission performance rates to be phased in over the period from 2022 through 2030. The rule is intended to reduced carbon dioxide emissions from the 2005 baseline by 28% in 2025 and 32% in 2030.

Legal challenges to the rule began when it was still being proposed. One action by an industry petitioner, joined by intervenors, including us, and another by a coalition of states led by West Virginia, asserted that the EPA does not have the authority to issue the regulations of existing power plants under section 111(d) of the CAA. The D.C. Circuit heard oral arguments on the challenges in April 2015. The petitions to enjoin the proposed rulemaking were denied as premature in June 2015. However, the D.C. Circuit court acknowledged that a legal challenge could be filed after the EPA issued a final rule. In September 2015 the D.C. Circuit Court refused to stay the rule, holding that it could not review the rule until it was published in the Federal Register which is occurred on October 23, 2015.

Since Federal Register publication on October 23, 2015, 39 separate petitions for review by approximately 157 entities have been filed in the U.S. Court of Appeals for the D.C. Circuit challenging the final rule. The petitions reflect challenges by 27 states and governmental entities, as well as challenges by utilities, industry groups, trade associations, coal companies, and other entities. All together, the petitions include legal challenges by over 100 entities. The lawsuits have been consolidated with the case filed by West Virginia and Texas (in which other States have also joined). On October 29, 2015, we filed a motion to intervene in the case filed by West Virginia and Texas, in support of the petitioning States. The motion was granted on January 11, 2016. Numerous states and cities have also been allowed to intervene in support of EPA.

On January 21, 2016, the D.C. Circuit Court denied the state and industry petitioners' motions to stay the implementation of the rule but provided for an expedited schedule for review of the rule, with oral arguments beginning on June 2, 2016. The state and industry petitioners appealed and filed application for state with the United States Supreme Court on January 27, 2016. On February 9, 2016, the Supreme Court overruled the lower court and granted the motion to stay implementation of the rule until its legal challenges are resolved.

EPA's Greenhouse Gas (GHG) Permitting Regulations for Major Emission Sources. 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. Also in May 2010, the EPA published final rules requiring permitting and control technology requirements for GHGs under the Prevention of Significant Deterioration (PSD) and Title V permitting programs, for major stationary emission sources, as defined by statutory emission thresholds, finding that such rules were necessitated or “triggered” by the EPA’s regulation of GHG’s from motor vehicles. These rules were upheld by the U.S. Court of Appeals (D.C. Circuit) on June 26, 2012. The U.S. Supreme Court granted certiorari to review the limited question of whether the EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases. On June 23, 2014, the U.S. Supreme Court ruled that EPA could not require PSD and Title V permitting for stationary sources that were not otherwise major sources of conventional pollutants, based solely on their potential GHG emissions. The Court upheld EPA's rule that a major emission source that is subject to the PSD program because of its emission of conventional pollutants must also employ the best available control technology for GHGs that exceed a certain threshold as determined by the EPA. EPA now requires sources that are otherwise "major" sources of conventional pollutants to apply best available control technology for GHG emissions, if those emissions would have the potential to exceed 75,000 tons per year. Individual states may have additional permitting requirements for GHGs.

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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. On remand, the D.C. Circuit court held on July 28, 2015 that certain of EPA’s Phase II emission budgets were invalid because they required more emissions reductions than necessary to achieve the desired air pollutant reduction in the relevant downwind states. The court did not vacate the rule but required the EPA to reconsider the invalid emissions budgets as to those states. On November 16, 2015, the EPA proposed the CSAPR Update Rule to address implementation of the 2008 ozone national air quality standards, proposing further reductions in nitrogen oxides to begin in 2017 in 23 states subject to CSAPR.

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 provided 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 needed more time to upgrade and complete those installations. 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. On June 29, 2015 the U.S. Supreme Court held that the EPA interpreted the CAA unreasonably when it deemed cost irrelevant to the decision to regulate power plants. The court reversed the D.C. Circuit Court and remanded the case for further proceedings. On December 1, 2015, in response to the court’s decision the EPA published in the Federal Register a proposed supplemental finding that consideration of costs does not alter the EPA’s previous determination to implement the MATS rule. On December 15, 2015, the D.C. Circuit Court issued an order providing that the rule will remain in effect while the EPA responds to the U.S. Supreme Court decision.

Stream Protection Rule. On July 27, 2015, the OSM issued its proposed Stream Protection Rule (SPR). The proposed rule would impact both surface and underground mining operations and would increase testing and monitoring requirements related to the quality or quantity of surface water and groundwater or the biological condition of streams. The SPR will also require the collection of increased pre-mining data about the site of the proposed mining operation and adjacent areas to establish a baseline for evaluation of the impacts of mining and the effectiveness of reclamation associated with returning streams to pre-mining conditions. The SPR was issued as a result of the D.C. Circuit Court’s decision in 2014 to vacate the then existing Stream Buffer Zone Rule. Peabody along with many other groups and operators have responded with to the proposed rule via the public comment process, which ended October 26, 2015. The final rule is expected in August 2016.

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 called the Waters of the United States (WOTUS) was proposed by the EPA in June 2014. A preliminary injunction was issued by the U.S. District Court in North Dakota in August 2015 and, on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the Clean Water Rule nationwide pending further action of the court. 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. 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 thereby requiring negotiation with the traditional owners (and potentially the payment of compensation) prior to the grant of certain mining tenements. 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. Typically mining proponents must also reach agreement with the owners of land underlying proposed mining tenements prior to the grant and/or conduct of mining activities or otherwise acquire the land. These arrangements generally involve the payment of compensation in lieu of the impacts of mining on the land.

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, Regional Planning Interests Act 2014, 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. The Mineral Resources Act 1989 is currently undergoing a thorough review and revision including significant changes to the management of overlapping coal and coal seam gas tenements and the coordination of activities. It is expected these new laws will come into effect in late 2016.

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 to make it mandatory for decision makers to consider the economic significance of coal resources when determining a development application for a mine and to give primacy to that consideration. This amendment was repealed in 2015. However, decision makers still have regard to the significance of a resource and the State and regional economic benefits of a proposed coal mine when considering a development application on the basis that it is an element of the "public interest" head of consideration contained in the legislation.

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

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In light of the recent discovery of six cases of pneumoconiosis in current and former coal mine workers in Queensland, the Department of Natural Resources has commissioned a review of the current coal mine workers' health assessment process to ensure it is effective in the early detection of respirable lung diseases such as pneumoconiosis.

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, bullying claims, industrial action and resolution of workplace disputes. Many of the workers employed in our mines are covered by enterprise agreements approved under the national system.

National Greenhouse and Energy Reporting Act 2007 (NGER Act). In 2007, a single, national reporting system relating to greenhouse gas emissions, energy use and energy production was introduced. The NGER Act imposes requirements for corporations meeting a certain threshold to register and report greenhouse gas emissions and abatement actions, as well as energy production and consumption. 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.

On July 1, 2016, amendments to the NGER Act will come into force which implement the Emission Reduction Fund Safeguard Mechanism. From that date, large designated facilities such as coal mines will be issued with a baseline for their covered emissions and must take steps to keep their emissions below the baseline or face penalties.

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. The Queensland Office of State Revenue issues determinations setting out its interpretation of the laws that impose royalties and provide guidance on how royalty rates should be calculated.

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 no expense related to the carbon pricing framework in 2015 and approximately $25 million and $40 million in 2014 and 2013, respectively. Accordingly, we anticipate a modest improvement in our future operating costs and expenses as a result of the repeal of this legislation.

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." In particular, on August 3, 2015, the EPA announced the final rules (which were published in the Federal Register on October 23, 2015) for regulating carbon dioxide emissions from existing and new fossil fuel-fired EGUs. EPA has set emission performance rates for existing plants to be phased in over the period from 2022 through 2030. This rule is intended to reduce carbon dioxide emissions from the 2005 baseline by 28% in 2025 and 32% in 2030. EPA has also set standards applying to new, modified and reconstructed sources beginning in 2015.

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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. Some states have initiated public utility proceedings that may establish values for carbon emissions. In a proceeding before the Minnesota Public Utilities Commission, a decision by an Administrative Law Judge is expected in April 2016 in which she will either recommend acceptance or rejection of (1) the Federal Social Cost of Carbon, (2) a different externality value or (3) maintenance of the current externality value.

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 (UNFCCC), established a binding set of greenhouse gas 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 were discussions to develop a treaty to replace the Kyoto Protocol after the expiration of its commitment period in 2012, including at the UNFCCC conferences in Cancun (2010), Durban (2011), Doha (2012) and Paris (2015). At the Durban conference, an ad hoc working group was established to develop a protocol, another legal instrument or an agreed outcome with legal force under the UNFCCC, applicable to all parties. At the Doha meeting, an amendment to the Kyoto Protocol was adopted, which included 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. During the UNFCCC conference in Paris, France in late 2015, an agreement was adopted calling for voluntary emissions reductions contributions after the second commitment period ends in 2020. The agreement will enter into force upon ratification and execution by 55 countries that account for at least 55% of global greenhouse gas emissions.

Australia's Parliament passed carbon pricing legislation in November 2011. The first three years of the program involved 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 stations 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. From time to time, we attempt to analyze the potential impact on the Company of as-yet-unadopted, potential laws, regulations and policies. Such analyses require that we make significant assumptions as to the specific provisions of such potential laws, regulations and policies. These analyses sometimes show that certain potential laws, regulations and policies, if implemented in the manner assumed by the analyses, could result in material adverse impacts on our operations, financial condition or cash flow, in view of the significant uncertainty surrounding each of these potential laws, regulations and policies. We do not believe that such analyses reasonably predict the quantitative impact that future laws, regulations or other policies may have on our results of operations, financial condition or cash flows.

Available Information

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

In addition, copies of our filings will be made available, free of charge, upon request by telephone at (314) 342-7900 or by mail at: Peabody Energy Corporation, Peabody Plaza, 701 Market Street, St. Louis, Missouri 63101-1826, attention: Investor Relations.

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Item 1A. Risk Factors.

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

Risks Associated with Our Operations

As a result of operating losses and negative cash flows from operations and our election to exercise a 30-day grace period with respect to certain interest payments, together with other factors, including the possibility that a covenant default or other event of default could cause certain of our indebtedness to become immediately due and payable (after the expiration of any applicable grace period), we may not have sufficient liquidity to sustain operations and to continue as a going concern.

We incurred a substantial loss from operations and had negative cash flows from operating activities for the year ended December 31, 2015. Our current operating plan indicates that we will continue to incur losses from operations and generate negative cash flows from operating activities. These projections and certain liquidity risks raise substantial doubt about whether we will meet our obligations as they become due within one year after the date of issuance of this report. We have also elected to exercise the 30-day grace period with respect to a $21.1 million semi-annual interest payment due March 15, 2016 on the 6.50% Senior Notes due September 2020 and a $50.0 million semi-annual interest payment due March 15, 2016 on the 10.00% Senior Secured Second Lien Notes due March 2022, as provided for in the indentures governing these notes. Failure to pay these interest amounts on March 15, 2016 is not immediately an event of default under the indentures governing these notes, but would become an event of default if the payment is not made within 30 days of such date. As a result of these factors, as well as the continued uncertainty around global coal fundamentals, the stagnated economic growth of certain major coal-importing nations, and the potential for significant additional regulatory requirements imposed on coal producers, among others, there exists substantial doubt whether we will be able to continue as a going concern. In addition, in February 2016, we borrowed approximately $945 million under the 2013 Revolver, the maximum amount available, for general corporate purposes.

The accompanying consolidated financial statements are prepared on a going concern basis and do not include any adjustments that might result from uncertainty about our ability to continue as a going concern, other than the reclassification of certain long-term debt and the related debt issuance costs to current liabilities and current assets, respectively. The report from our independent registered public accounting firm on our consolidated financial statements for the year ended December 31, 2015 includes an uncertainty paragraph that summarizes the salient facts and conditions that raise substantial doubt about our ability to continue as a going concern.

Our 2013 Credit Facility and its related governing documents contain requirements (as more fully described under "Risks Associated with Our Indebtedness" below) that, among other things, require us to comply with certain financial covenants and furnish our audited financial statements as soon as available, but in any event within 90 days after the fiscal year end without a “going concern” uncertainty paragraph in the auditor’s opinion. Our consolidated financial statements for the year ended December 31, 2015 included herein contain a "going concern" uncertainty paragraph. In addition, we currently anticipate that our reported Adjusted EBITDA and other sources of earnings or adjustments used to calculate Consolidated EBITDA (if such other sources of earnings or adjustments do not include the proceeds of certain targeted asset sales) will fall below our Consolidated Net Cash Interest Charges during 2016, and we anticipate we will not comply with our financial covenants as of March 31, 2016. Absent waivers or cures, non-compliance with such covenants would constitute a default under the 2013 Credit Facility. As a result, all indebtedness under the 2013 Credit Facility could be declared immediately due and payable upon the occurrence of an event of default (after the expiration of any applicable grace period). It is possible we could obtain waivers from our lenders; however, the aforementioned projections and certain liquidity risks raise substantial doubt about whether we will meet our obligations as they become due within one year after the date of issuance of this report.

We are currently exploring alternatives for other sources of capital for ongoing liquidity needs and transactions to enhance our ability to comply with the financial covenants under our 2013 Credit Facility. We are working to improve our operating performance and our cash, liquidity and financial position. This includes: pursuing the sale of non-strategic surplus land and coal reserves as well as existing mines, particularly the sale of our El Segundo and Lee Ranch coal mines and related assets located in New Mexico and our Twentymile Mine in Colorado; continuing to drive cost improvements across the company, attempting to negotiate alternative payment terms with creditors; maintaining our current level of self-bonding and/or replacing self-bonding with other financial instruments on reasonable terms; evaluating potential debt buybacks, debt exchanges and new financing to improve our liquidity and reduce our financial obligations; and obtaining waivers of going concern and financial covenant violations under the 2013 Credit Facility. We have engaged financial and other advisors to assist us in those efforts.

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However, there can be no assurance that our plan to improve our operating performance and financial position will be successful or that we will be able to obtain additional financing on commercially reasonable terms or at all. As a result, our liquidity and ability to timely pay our obligations when due could be adversely affected. Furthermore, our creditors may resist renegotiation or lengthening of payment and other terms through legal action or otherwise. If we are not able to timely, successfully or efficiently implement the strategies that we are pursuing to improve our operating performance and financial position, obtain alternative sources of capital or otherwise meet our liquidity needs, we may need to voluntarily seek protection under Chapter 11 of the U.S. Bankruptcy Code.

Our profitability depends upon the prices we receive for our coal.

Depressed coal prices have reduced our revenues, and sustained prices at current levels or further declines in coal prices will adversely affect our operating results and financial condition. Further declines in coal prices will adversely affect the value of our coal reserves.

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 or subsidizing 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.

Coal prices are currently depressed based on a number of factors, many of which are outside our control. If coal prices decline further, our operating results and profitability and value of our coal reserves could be materially and adversely affected. For example, our revenues decreased during the year ended December 31, 2015, as compared to the prior year by $1,183.0 million, primarily due to lower realized coal pricing and lower sales volumes driven by demand and production factors described in this risk factor.

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.

Thermal coal accounted for the majority of our coal sales during 2015. The majority of our sales of thermal coal were to electric power generators. The demand for coal consumed for electric power generation is affected by many of the factors described above, but primarily by (i) the overall demand for electricity; (ii) the availability, quality and price of competing fuels, such as natural gas, nuclear fuel, oil and alternative energy sources; (iii) increasingly stringent environmental and other governmental regulations; and (iv) the coal inventories of utilities. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. Many of the new power plants in the U.S. may be fueled by natural gas because gas-fired plants are viewed as cheaper to construct and permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators. Increasingly stringent regulations have also reduced the number of new power plants being built. These trends have reduced demand for our coal and the related prices. Any further reduction in the amount of coal consumed by electric power generators could reduce the price of coal that we mine and sell.

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Lower demand for metallurgical coal by steel producers would reduce our revenues and could further reduce the price of our metallurgical coal. We produce metallurgical coal that is used in the global steel industry. Metallurgical coal accounted for approximately 21.4% and 24.1% of our coal sales revenue in 2015 and 2014, respectively. Any deterioration in conditions in the steel industry, including the demand for steel and the continued financial condition of the industry, would reduce the demand for our metallurgical coal. Lower demand for metallurgical coal in international markets would reduce the amount of metallurgical coal that we sell and the prices that we receive for it, thereby reducing our revenues and adversely impacting our earnings and the value of our coal reserves.

Additionally, we compete with numerous other domestic and foreign coal producers for domestic and international sales. This competition affects domestic and foreign coal prices and our ability to attract and retain customers. Overcapacity and increased production within the coal industry, both domestically and internationally, could materially reduce coal prices and therefore materially reduce our revenues and profitability. In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas. Further declines in the price of natural gas, or continued low natural gas prices, could cause demand for coal to decrease and adversely affect the price of coal. Sustained periods of low natural gas prices or other fuels may also cause utilities to phase out or close existing coal-fired power plants or reduce construction of new coal-fired power plants, which could have a material adverse effect on demand and prices for our coal, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

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 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, 2015, we derived 26% of our total revenues from our five largest customers, similar to the prior year. Those five customers were supplied primarily from 31 coal supply agreements (excluding trading transactions) expiring at various times from 2016 to 2026. The contract contributing the greatest amount of annual revenue in 2015 was approximately $285 million, or approximately 5% of our 2015 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 (including contractually obligated purchases) due to lack of demand and oversupply, cost of competing fuels and environmental and other governmental regulations.

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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, which occurred at December 31, 2015. As such, beginning January 1, 2016, we will be required to recognize the mark-to-market movements through current year earnings, possibly resulting in increased volatility in our income in future periods. In addition, to the extent that we engage in hedging activities, we may be prevented from realizing the benefits of future price 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.

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 2015 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. These new customers may have credit ratings that are below investment grade or are not rated. If deterioration of the creditworthiness of our customers occurs or they fail to perform the terms of their contracts with us, our accounts receivable securitization program and our business could be adversely affected.

Risks inherent to mining could increase the cost of operating our business.

Our mining operations are subject to conditions that can impact the safety of our workforce, or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include fires and explosions from methane gas or coal dust; accidental mine water discharges; weather, flooding and natural disasters; unexpected maintenance problems; unforeseen delays in implementation of mining technologies that are new to our operations; key equipment failures; variations in coal seam thickness; variations in coal quality; variations in the amount of rock and soil overlying the coal deposit; variations in rock and other natural materials and variations in geologic conditions. We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, such conditions could occur and have a substantial impact on our results of operations, financial condition or cash flows.

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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.

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 unfavorably affect our profitability.

We have substantial take-or-pay arrangements, predominately in Australia, totaling $2.2 billion, with terms ranging up to 27 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 have completed several conversions to owner-operator status at certain of our Australian operations, a portion of our sales volume continues to come from mines that utilize contract miners. Employee relations at mines that use contract miners are the responsibility of the contractor.

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

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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" to the accompanying consolidated financial statements, we recognized aggregate asset impairment and mine closure costs of $1,277.8 million, $154.4 million and $528.3 million in 2015, 2014 and 2013, 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.

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

As of December 31, 2015, we had approximately 7,600 employees (excluding employees that were employed at operations classified as discontinued), which included approximately 5,700 hourly employees. Approximately 37% of our hourly employees were represented by organized labor unions and generated 20% of 2015 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, 2015, we had $1,430.8 million of self bonding in place for our reclamation obligations. As of December 31, 2015, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of $1,045.7 million, of which $592.3 million was for post-mining reclamation, $75.0 million related to workers' compensation obligations, $110.5 million was for coal lease obligations and $267.9 million was for other obligations, including road maintenance and performance guarantees. During 2015, we were required to increase our total posted letters of credit by $429.2 million to the issuing parties of certain of our surety bonds and bank guarantees, whereas we had not previously been required to do so. Surety bonds are typically renewable on a yearly basis. Surety bond issuers 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 2013 Credit Facility 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 our accounts receivable securitization program or a default or lack of availability of letters of credit thereunder.

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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, changes in our financial condition or for any other reason, we would be required to obtain replacement financial assurances. Further, self-bonding is permitted at the discretion of each state. While we have historically demonstrated compliance with the applicable financial requirements in the states in which we self-bond, our self-bonding status may be challenged or withdrawn at any time. The OSM has recently issued notices to one or more states alleging possible violations relating to the continued self-bonding by coal companies, including us, in that state. The notices require the violation to be corrected or for the state to explain why a violation does not exist. As a result of any adverse change in our ability to self-bond, our costs would increase and our liquidity available for other uses would be reduced to the extent of any collateral required to obtain replacement financial assurances.

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

The coal mining industry is subject to regulation by federal, state and local authorities with respect to matters such as:

- employee health and safety;
- limitations on land use;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- the storage, treatment and disposal of wastes;
- remediation of contaminated soil and groundwater;
- air quality standards;
- water pollution;
- protection of human health, plant-life and wildlife, including endangered or threatened species;
- protection of wetlands;
- the discharge of materials into the environment; and
- the effects of mining on surface water and groundwater quality and availability.

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.

The possibility exists that new legislation or regulations and orders, including without limitation related to the environment or employee health and safety may be adopted and may materially adversely affect our mining operations, our cost structure 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.

For additional information, see the sections entitled "Regulatory Matters-U.S." and "Regulatory Matters-Australia" for more information about the various regulations affecting us.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. A number of laws, including in the U.S., CERCLA and the Resource Conservation and Recovery Act (RCRA), 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 RCRA, 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.

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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.

We may be unable to obtain and renew permits necessary for our operations, which would reduce our production, cash flows and profitability.

Numerous governmental and tribal permits and approvals are required for mining operations. The permitting rules, and the interpretations of these rules, are complex and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult or impractical. As part of this process, 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. In recent years, the permitting required for coal mining has been the subject of increasingly stringent regulatory and administrative requirements and extensive litigation by environmental groups.

The costs, liabilities and requirements associated with these regulations and opposition may be costly and time-consuming and may delay commencement or continuation of exploration or production and as a result, adversely affect our coal production, cash flows and profitability. Further, required permits may not be issued or renewed in a timely fashion or at all, or permits issued or renewed may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow and profitability.

The U.S. Army Corps of Engineers (Corps) regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the Clean Water Act (CWA) requires mining companies like us 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. In recent years, the Section 404 permitting process has been subject to increasingly stringent regulatory and administrative requirements and a series of court challenges, which have resulted in increased costs and delays in the permitting process. Additionally, increasingly stringent requirements governing coal mining also are being considered or implemented under the Surface Mining Control and Reclamation Act, the National Pollution Discharge Elimination System permit process and various other environmental programs. Potential laws, regulations and policies could result in material adverse impacts on our operations, financial condition or cash flow, in view of the significant uncertainty surrounding each of these potential laws, regulations and policies.

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.

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

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Moreover, the amount of proven and probable coal reserves described in Part I, Item 2. “Properties” involved the use of certain estimates and those estimates could be inaccurate. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include geological conditions, historical production from the area compared with production from other producing areas, the assumed effects of regulations and taxes by governmental agencies and assumptions governing future prices and future operating costs. Actual production, revenues and expenditures with respect to our coal reserves may vary materially from estimates.

Our future success depends upon our conducting successful exploration and development activities or acquiring properties containing economically recoverable reserves. Our current strategy includes increasing our reserves through acquisitions of government and other leases and producing properties and continuing to use our existing properties and infrastructure. In certain locations, leases for oil, natural gas and coalbed methane reserves are located on, or adjacent to, some of our reserves, potentially creating conflicting interests between us and lessees of those interests. Other lessees’ rights relating to these mineral interests could prevent, delay or increase the cost of developing our coal reserves. These lessees may also seek damages from us based on claims that our coal mining operations impair their interests. Additionally, the U.S. federal government limits the amount of federal land that may be leased by any company to 75,000 acres in any one state and 150,000 acres nationwide. As of December 31, 2015, we leased a total of 69,145 acres from the federal government subject to those limitations. On January 15, 2016, the Interior Department announced that it will perform a review of the federal coal leasing program. The Secretary of the Interior Sally Jewell ordered a pause on issuing new coal leases which the Interior Department expects to continue for three years. If this limitation were to continue significantly beyond three years, it could restrict our ability to lease additional U.S. federal lands and coal reserves critical to our Western U.S mining and Powder River Basin mining segments.

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 order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. 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 or have not met minimum quantity or product royalty requirements. 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 exposure to 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 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 and our liquidity 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 2015, 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 $23.5 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.

We could be 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.

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Risks Associated with Our Indebtedness

Our financial performance could be adversely affected by our substantial indebtedness.

As of December 31, 2015, our total indebtedness was $6.3 billion, and we had $940.0 million of maximum borrowing capacity under the 2013 Revolver portion of our 2013 Credit Facility, net of outstanding letters of credit. Our 2013 Credit Facility and our Senior Secured Second Lien Notes contain covenants limiting the amount of indebtedness we may incur, however, the indentures governing our Convertible Junior Subordinated Debentures (the Debentures) and the 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 addition of new debt to our current debt levels could increase the related risks that we now face. Our substantial indebtedness could have important consequences, including, but not limited to:

- increasing the costs of borrowing under our existing credit facilities or newly issued debt obligations;
- making it more difficult for us to satisfy the financial covenants in our 2013 Revolver;
- 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;
- limiting our ability to refinance our indebtedness when it becomes due;
- making it more difficult to obtain bank guarantees, 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;
- demands by contract counterparties for adequate assurances or the refusal of third parties to contract with us could impact performance and reduce liquidity;
- requiring us to provide credit support, or additional credit support, for our current obligations and future obligations which we may seek to incur;
- 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, which could also result in a cross-default or cross-acceleration of our other indebtedness. As noted above, our current operating plan indicates that we will incur a loss from operations, generate negative cash flows and, unless we achieve certain targeted asset sales, violate certain financial and restrictive covenants. The inclusion of a "going concern" explanatory paragraph in the auditor's opinion covering our audited financial statements contained herein, absent a waiver or cure, would constitute a default under the 2013 Credit Facility after the expiration of any applicable grace period.

Previous downgrades in our credit ratings have resulted in us posting additional collateral with respect to derivative trading instruments and certain agreements with our customers. Any future downgrade in our credit ratings could result in additional requirements to post collateral on derivative trading instruments and certain agreements with our customers, 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.

If our cash flows and capital resources are insufficient to fund our debt services obligations, we may be forced to sell assets, seek additional capital to attempt to meet our debt service and other obligations or seek to restructure or refinance certain debt obligations. We have engaged in discussions with certain holders of our debt regarding debt exchanges and debt buybacks, as well as new financings. However, these alternative measures may not be successful and may not permit us to meet our scheduled debt services obligations. In this regard, certain agreements governing our indebtedness restrict our ability to sell assets and the manner in which we may use proceeds from asset sales. We also may not be able to complete any such asset sales or realize sufficient proceeds to meet debt service obligations then due. In addition, our ability to restructure our debt obligations may be impacted by cash tax liabilities that result from the cancellation of debt income if we are unable to offset that income with tax losses or other tax planning strategies. If the actions described above are not successful and we are unable to meet our debt service obligations when due, we could be required to reorganize our company in its entirety, including through bankruptcy proceedings.

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Our ability to meet our financial obligations and fund our operations is dependent upon market conditions and our continued access to borrowing capacity of our existing borrowing facilities.

Liquidity risk refers to the risk that we may not be able to generate or otherwise obtain funds at reasonable rates to meet our financial obligations and fund our operations. In addition to cash and cash equivalents, our liquidity typically includes the available balances from the 2013 Revolver under the 2013 Credit Facility and our accounts receivable securitization program that expires in April 2016. In February 2016, we borrowed approximately $945 million under our 2013 Revolver, which represented the then-remaining undrawn available amount. In order for our liquidity to be sufficient to meet our anticipated capital requirements, we must maintain our cash or, to the extent amounts once again become available for borrowing, continue to have access to a substantial portion of our maximum borrowing capacity under the 2013 Revolver. Our ability to borrow under the 2013 Revolver is dependent upon our ability to comply with the covenants in the 2013 Credit Facility. As noted above, our current operating plan indicates that we will incur a loss from operations, generate negative cash flows and, unless we achieve certain targeted asset sales, violate certain financial and restrictive covenants. The inclusion of a "going concern" explanatory paragraph in the auditor's opinion covering our audited financial statements contained herein, absent a waiver or cure, would constitute a default under the 2013 Credit Facility after the expiration of any applicable grace period.

As of March 11, 2016, our available liquidity declined to $0.9 billion, which consisted primarily of cash and cash equivalents. The decline since December 31, 2015 was primarily due to operational expenditures and the issuance of additional letters of credit.

Due to significant pressure on our business and current market conditions facing the coal industry, we have experienced losses of $1,996.0 million and $787.0 million in 2015 and 2014, respectively, and cash outflows from operations of $14.4 million in 2015. We expect to continue to experience operating losses and cash outflows from operations in the coming quarters, until the coal industry stabilizes. We have taken steps to reduce the cash outflow from operations in the near term through a realignment of our cost structure and anticipated reductions in production volumes, but these actions will not entirely address our cash outflows from operations.

Other factors that could materially adversely impact our liquidity include an inability to maintain our current level of self-bonding, requirements to provide additional collateral to support our operations, an inability to renew our accounts receivable securitization program at an appropriate capacity when it expires in April 2016, further downgrades of our credit ratings and additional obligations or liabilities that we may incur as a result of the Patriot bankruptcy. Access to additional funds from liquidity-generating transactions or other sources of external financing may not be available to us and, if available, would be subject to market conditions and certain limitations including our credit rating and covenant restrictions in the agreements governing our debt, including our 2013 Credit Facility.

We have engaged in discussions with holders of our debt regarding new financings as well as debt exchanges and debt buybacks to improve our liquidity and reduce our financial obligations. If we are not able to timely, successfully or efficiently implement the strategies that we are pursuing to improve our operating performance and financial position, obtain alternative sources of capital or otherwise meet our liquidity needs or maintain covenant compliance under our 2013 Credit Facility, we may need to voluntarily seek protection under Chapter 11 of the U.S. Bankruptcy Code.

The covenants in our 2013 Credit Facility, and the indentures governing our Senior Notes, Senior Secured Second Lien 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 Senior Secured Second Lien Notes 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 consolidated net secured first lien leverage ratio and a minimum consolidated interest coverage ratio, each as defined therein. The covenants also place limitations on our investments in joint ventures and unrestricted subsidiaries, indebtedness and the imposition of liens on our assets. Also, because our ability to borrow under the 2013 Credit Facility is conditioned upon compliance with these covenants, any available borrowing capacity under the 2013 Credit Facility may be limited or may be altogether precluded. 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 borrowing capacity under the 2013 Credit Facility may be limited or may be altogether precluded. As noted above, our current operating plan indicates that we will incur a loss from operations, generate negative cash flows and, unless we achieve certain targeted asset sales, violate certain financial and restrictive covenants in 2016. The inclusion of a "going concern" explanatory paragraph in the auditor's opinion covering our audited financial statements contained herein, absent a waiver or cure, would constitute a default under the 2013 Credit Facility after the expiration of any applicable grace period.

We currently anticipate that our reported Adjusted EBITDA and other sources of earnings or adjustments used to calculate Consolidated EBITDA (if such other sources of earnings or adjustments do not include the proceeds of certain targeted asset sales) will fall below our Consolidated Net Cash Interest Charges during 2016, and we anticipate we will not comply with our financial covenants as of March 31, 2016. If we violate these covenants and are unable to obtain waivers from our lenders and the debt under our 2013 Credit Facility is accelerated, there would be an event of default under our Senior Notes, and our Senior Secured Second Lien Notes and the debt owing thereunder 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 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.
Under the indentures governing our Senior Notes, the amount of Indebtedness (as defined in the indentures governing the Senior Notes) that may be secured by Principal Property and Capital Stock (each as defined in the Senior Notes indentures) is limited in amount, unless the Senior Notes are secured on an equal and ratable basis. Our 2013 Credit Facility and our Senior Secured Second Lien Notes are secured by Principal Property and Capital Stock, among other collateral, in a manner that uses substantially all of such limited amount. While the 2013 Credit Facility and our Senior Secured Second Lien Notes provide us with flexibility to secure certain other debt with Principal Property and Capital Stock while maintaining compliance with the terms of our Senior Notes indentures and not requiring such notes to be equally and ratably secured, our ability to incur such other secured debt is limited, and our ability to secure any debt in the future, whether or not secured by Principal Property and Capital Stock, may be negatively affected by such constraints. In addition, under the 2013 Credit Facility, if we cannot meet our debt service obligations, payment of our outstanding debt could be accelerated, 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.

The conversion of our Debentures, sales of additional shares of our common stock and the exercise or granting of additional equity securities 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.
Future issuances of equity securities, including issuances pursuant to outstanding stock-based awards under our long-term incentive plans, could dilute the interests of our existing stockholders and could cause the market price for our common stock to decline. We may issue equity or equity-linked securities in the future for a number of reasons, including to finance our operations and business strategy, adjust our ratio of debt to equity, satisfy claims or obligations or for other reasons.

We may be unable to repurchase or make payments associated with our debt if we experience a change of control

If we experiences specific kinds of changes in control and the credit rating assigned to our Senior Notes declines below specified levels within 90 days of that time, holders of such notes have the right to require us to repurchase their notes at a repurchase price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to the date of repurchase. In addition, as discussed above, certain provisions of our Debentures provide that upon the occurrence of certain transactions constituting a change of control, 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. If a change of control were to occur, we may not have sufficient funds to purchase our Senior Notes or pay amounts required by our Debentures. We also might not be able to obtain additional financing to fund those purchases and payments. Our failure to repurchase or make payments with respect to our Senior Notes and Debentures upon a change of control would cause a default under the relevant indentures and a cross default under our other indentures and our credit facility. A change of control (as defined for purposes of our credit facility) is also an event of default under the credit facility that would permit lenders to accelerate the maturity of certain borrowings.

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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, 2015, we had gross deferred income tax assets and liabilities of $2,597.1 million and $1,167.0 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 $1,447.3 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.
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.
We are exposed to risk of loss due to Patriot's bankruptcy.
In 2012, Patriot Coal Company and certain of its wholly owned subsidiaries (Patriot) filed voluntary petitions for relief under Chapter 11 of Title 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. In May 2015, Patriot again filed voluntary petitions for relief under Chapter 11 of Title 11 of the U.S. Code in the Eastern District of Virginia and subsequently initiated a process to sell some or all of its assets to qualified third-party bidders. On October 9, 2015, the bankruptcy court overseeing Patriot's current bankruptcy confirmed a plan of reorganization that sold substantially all of Patriot's assets to two buyers and contributed the remainder to a liquidating trust. The plan became effective in late October 2015.
We have exposure related to a total of $83.1 million of credit support we provided to Patriot pursuant to the 2013 definitive settlement agreement (net of $8.5 million of underlying liabilities assumed and $29.9 million of financial instruments drawn upon in 2015). Refer to Note 25. "Matters Related to the Bankruptcy of Patriot Coal Corporation" to the accompanying consolidated financial statements for additional information surrounding these risks.
By statute, we remain secondarily liable for the black lung liabilities related to Patriot’s workers employed by our former subsidiaries. Whether we will ultimately be required to fund certain of those obligations in the future as a result of Patriot’s May 2015 bankruptcy remains uncertain. We do believe that it is probable that we will be required to fund a portion of these obligations in the future and recorded a charge to "Loss from discontinued operations, net of income taxes" of $114.4 million, net of $15.0 million previously accrued credit support related to Patriot's federal black lung obligations, during the year ended December 31, 2015. Refer to Note 25. "Matters Related to the Bankruptcy of Patriot Coal Corporation" to the accompanying consolidated financial statements for additional information surrounding these risks.
Additionally, we are a party to proceedings alleging we have withdrawal liability of $644.2 million to the UMWA 1974 Pension Plan, which is discussed in Note 25. "Matters Related to the Bankruptcy of Patriot Coal Corporation". Other parties may make claims against us in relation to Patriot's bankruptcy, although we are unaware of any other claims at this time.
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 employees. Our total accumulated postretirement benefit obligation related to such benefits was a liability of $776.1 million as of December 31, 2015, of which $53.2 million was classified as a current liability. Certain of our U.S. subsidiaries also sponsor defined benefit pension plans. Net pension liabilities were $182.0 million as of December 31, 2015, of which $1.6 million was classified a current liability.

These liabilities are actuarially determined and we use various actuarial assumptions, including the discount rate, future cost trends, and rates of return on plan assets 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. A decrease in the discount rate used to determine our postretirement benefit and defined benefit pension obligations could result in an increase in the valuation of these obligations, thereby increasing the cost in subsequent fiscal years. We have made assumptions related to future trends for medical care costs in the estimates of retiree health care obligations. Our medical trend assumption is developed by annually examining the historical trend of our cost per claim data. 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 healthcare benefits provided by the government could increase our obligation to satisfy these or additional obligations. Additionally, our reported defined benefit pension funding status may be affected, and we may be required to increase employer contributions, due to increases in our defined benefit pension obligation or poor financial performance in asset markets in future years.

Our defined benefit pension plans are subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended (ERISA). It is implicit in our underlying assumptions that those plans continue to operate in the normal course of business. However, the Pension Benefit Guarantee Corporation (PBGC) may terminate our plans under certain circumstances pursuant to ERISA laws, including in the event that the PBGC concludes that its risk may increase unreasonably if such plans continue to operate based on its assessment of the plans' funded status, our financial condition or other factors. Termination of the plans would require us to provide immediate funding or other financial assurance to the PBGC for all or a substantial portion of the underfunded amounts, as determined by the PBGC based on its own assumptions. Those assumptions may differ from our own. Any of those consequences could have a material adverse effect on our results of operations, financial conditions or available liquidity.

Our common stock could be delisted or be suspended from trading.

Our common stock is currently listed on the New York Stock Exchange (NYSE). In order for our common stock to continue to be listed on the NYSE, we are required to comply with various quantitative and qualitative listing standards. A renewed or continued decline in the closing price of our common stock on the NYSE could result in a breach of these requirements. If we were not able to cure the breach, the NYSE could commence suspension or delisting procedures in respect of our common stock. The commencement of suspension or delisting procedures by an exchange remains, at all times, at the discretion of such exchange and would be publicly announced by the exchange. If a suspension or delisting were to occur, there would be significantly less liquidity in the suspended or delisted securities. In addition, our ability to raise capital and compensate personnel by means of share-based compensation would be greatly impaired. Furthermore, with respect to any suspended or delisted securities, we would expect decreases in institutional and other investor demand, analyst coverage, market making activity and information available concerning trading prices and volume, and fewer broker-dealers would be willing to execute trades with respect to such securities. A suspension or delisting would likely decrease the attractiveness of our common stock to investors and cause the trading volume of our common stock to decline, which could result in a further decline in the market price of our common stock.

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 or coal-fueled power plant closures. 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. From time to time, we attempt to analyze the potential impact on the Company of as-yet-unadopted potential laws, regulations and policies. Such analyses require that we make significant assumptions as to the specific provisions of such potential laws, regulations and policies. These analyses sometimes show that certain potential laws, regulations and policies, if implemented in the manner assumed by the analyses, could result in material adverse impacts on our operations, financial condition or cash flow, in view of the significant uncertainty surrounding each of these potential laws, regulations and policies. We do not believe that such analyses reasonably predict the quantitative impact that future 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. "Summary of Significant Accounting Policies" 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 6.3 billion tons of proven and probable coal reserves as of December 31, 2015. An estimated 5.5 billion tons of our attributable proven and probable coal reserves are in the U.S., with the remainder in Australia. Approximately 73% of our Australian proven and probable coal reserves, or 624 million tons, are metallurgical coal, comprised of approximately 268 million and 356 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 64% of our reserves, or 4.0 billion tons, are compliance coal and 36% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). We own approximately 27% of these reserves and lease property containing the remaining 73%. 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, 2015 [1]		
Operating Regions	Locations	Owned Tons	Leased Tons	Total Tons
		(Tons in millions)		
Midwest	Illinois, Indiana and Kentucky	1,497	492	1,989
Powder River Basin	Wyoming	—	2,960	2,960
Southwest	Arizona and New Mexico [3]	171	229	400
Colorado	Colorado [3]	18	108	126
Total United States		1,686	3,789	5,475
New South Wales	Australia	—	290	290
Queensland	Australia	—	571	571
Total Australia		—	861	861
Total Proven and Probable Coal Reserves		1,686	4,650	6,336

(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 generally 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 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, 2015 reflected a net reduction compared to the prior year of 1.2 billion tons of coal reserves. The decrease was driven by adverse changes in economic factors, mine plan changes and the sale of non-strategic coal reserves, partially offset from acquisitions and new drilling with the addition of 50.5 million production tons.

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, 2015 reserve estimates for New South Wales region in Australia were audited by Palaris Australia Pty Ltd, an independent mining and geological consulting firm, which included a review of the data, procedures and parameters employed by us in developing our New South Wales 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 New South Wales 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, 2015, we leased 7,687 acres of federal land in Colorado, 640 acres in New Mexico and 52,556 acres in Wyoming, for a total of 60,883 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 6.3 billion tons, we believe that we have sufficient coal reserves to replace capacity from depleting mines for the foreseeable future and that our significant coal reserve holdings is one of our competitive strengths. We believe that the current level of production at our major mines is sustainable for the foreseeable future.

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The following charts provide a summary, by mining complex, of production (in descending order by region) for the years ended December 31, 2015, 2014 and 2013, tonnage of coal reserves that is assigned to our active operating mines, our property interest in those reserves and other characteristics of the facilities.

SUMMARY OF COAL PRODUCTION AND SULFUR CONTENT OF ASSIGNED RESERVES

(Tons in Millions)

	Production				Sulfur Content of Assigned Reserves as of December 31, 2015 (1)			
					<1.2 lbs.	>1.2 to 2.5 lbs.	>2.5 lbs.	As
Geographic Region /	Year Ended December 31,			Type of	Sulfur Dioxide per	Sulfur Dioxide per	Sulfur Dioxide per	Received Btu per
Mining Complex	2015	2014	2013	Coal	Million Btu	Million Btu	Million Btu	pound (2)
Midwest:								
Bear Run	7.9	8.4	8.2	T	4	26	220	11,500
Francisco Underground	2.9	3.1	2.9	T	—	—	27	11,500
Gateway/Gateway North	1.8	2.5	2.8	T	—	—	66	10,800
Wild Boar	2.7	3.5	3.6	T	—	—	38	11,100
Wildcat Hills Underground	1.7	2.0	1.6	T	—	—	24	12,100
Cottage Grove	1.1	1.9	2.0	T	—	—	5	12,200
Somerville Central	3.0	3.4	4.1	T	—	—	20	11,200
Viking - Corning Pit (Closed in 2014)	—	0.1	1.1	T	—	—	—	NA
Total	21.1	24.9	26.3		4	26	400	
Powder River Basin:								
North Antelope Rochelle	109.3	118.0	111.0	T	2,018	—	—	8,800
Rawhide	15.2	15.4	14.2	T	254	57	2	8,300
Caballo	11.4	8.0	9.0	T	594	31	4	8,400
Total	135.9	141.4	134.2		2,866	88	6	
Southwest:								
El Segundo (3)	7.5	8.4	8.7	T	16	42	40	9,000
Kayenta	6.8	8.1	7.2	T	142	63	3	10,600
Lee Ranch (3)	—	—	—	T	18	67	9	9,400
Total	14.3	16.5	15.9		176	172	52	
Colorado:								
Twentymile (3)	3.5	6.7	7.2	T	42	—	—	11,200
Australia:								
Wilpinjong	12.0	14.4	13.3	T	154	—	—	10,000
Wambo (4)	6.5	6.5	6.9	M/T	108	—	—	11,800
Millennium	4.4	3.9	3.5	M/P	18	—	—	12,600
Coppabella	2.8	3.2	3.2	P	54	—	—	12,600

North Goonyella	2.6	2.9	2.3	M	96	—	—	12,700
Moorvale	2.2	2.4	2.1	P	11	—	—	12,300
Metropolitan	2.1	2.5	1.5	M	28	—	—	12,600
Burton	1.3	1.9	2.0	M/T	9	—	—	12,700
Middlemount (5)	—	—	—	M/P	30	—	—	12,300
Total	33.9	37.7	34.8		508	—	—	
Total Continuing Operations	208.7	227.2	218.4		3,596	286	458	
Discontinued Operations	—	—	4.0		—	—	—	
Total Assigned	208.7	227.2	222.4		3,596	286	458	

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

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ASSIGNED RESERVES (6)
AS OF DECEMBER 31, 2015

(Tons in Millions)		Attributable Ownership					100% Project Basis				
Geographic Region/Mining Complex	Interest	Proven and Probable Reserves	Owned	Leased	Surface	Underground	Proven and Probable Reserves	Owned	Leased	Surface	Underground
Midwest:											
Bear Run	100%	250	109	141	250	—	250	109	141	250	—
Gateway/Gateway North	100%	66	64	2	—	66	66	64	2	—	66
Francisco Underground	100%	27	5	22	—	27	27	5	22	—	27
Wildcat Hills Underground	100%	24	11	13	—	24	24	11	13	—	24
Somerville Central	100%	20	17	3	20	—	20	17	3	20	—
Wild Boar	100%	38	21	17	38	—	38	21	17	38	—
Cottage Grove	100%	5	3	2	5	—	5	3	2	5	—
Total		430	230	200	313	117					
Powder River Basin:											
North Antelope Rochelle	100%	2,018	—	2,018	2,018	—	2,018	—	2,018	2,018	—
Caballo	100%	629	—	629	629	—	629	—	629	629	—
Rawhide	100%	313	—	313	313	—	313	—	313	313	—
Total		2,960	—	2,960	2,960	—					
Southwest:											
Kayenta	100%	208	—	208	208	—	208	—	208	208	—
El Segundo (3)	100%	98	80	18	98	—	98	80	18	98	—
Lee Ranch (3)	100%	94	91	3	94	—	94	91	3	94	—
Total		400	171	229	400	—					
Colorado:											
Twentymile (3)	100%	42	11	31	—	42	42	11	31	—	42
Australia:											
Wilpinjong	100%	154	—	154	154	—	154	—	154	154	—
Wambo (4)	100%	108	—	108	25	83	108	—	108	25	83
North Goonyella	100%	96	—	96	—	96	96	—	96	—	96
Coppabella	73.3%	54	—	54	54	—	74	—	74	74	—
Metropolitan	100%	28	—	28	—	28	28	—	28	—	28
Millennium	100%	18	—	18	18	—	18	—	18	18	—
Moorvale	73.3%	11	—	11	11	—	15	—	15	15	—
Burton	100%	9	—	9	9	—	9	—	9	9	—

Middlemount [5]	50.0%	30	—	30	30	—	60	—	60	60	—
Total		508	—	508	301	207					
Total Assigned		4,340	412	3,928	3,974	366					

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES (6)
AS OF DECEMBER 31, 2015
(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	95	1,409	1,504	674	830	95	1,409	1,504	674	830
Indiana	335	26	361	297	64	335	26	361	297	64
Kentucky (7)	—	124	124	55	69	—	124	124	55	69
Total	430	1,559	1,989	1,026	963					
Powder River Basin (Wyoming)	2,960	—	2,960	2,831	129	2,960	—	2,960	2,831	129
Southwest:										
Arizona	208	—	208	208	—	208	—	208	208	—
New Mexico (3)	192	—	192	192	—	192	—	192	192	—
Total	400	—	400	400	—					
Colorado (3)	42	84	126	81	45	42	84	126	81	45