

PEABODY ENERGY CORP
Form 10-K
March 22, 2017
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2016

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Commission File Number 1-16463

PEABODY ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

701 Market Street, St. Louis, Missouri

(Address of principal executive offices)

(314) 342-3400

Registrant's telephone number, including area code

Securities Registered Pursuant to Section 12(b) of the Act:

None

Securities Registered Pursuant to Section 12(g) of the Act:

Title of Each Class

Common Stock, par value \$0.01 per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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 No

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

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

Form 10-K.

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

(Do not check if a smaller reporting company)

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Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

Aggregate market value of the voting stock held by non-affiliates (stockholders who are not directors or executive officers) of the Registrant, calculated using the closing price on June 30, 2016: Common Stock, par value \$0.01 per share, \$25.3 million.

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of March 15, 2017: Common Stock, par value \$0.01 per share, 18,491,188 shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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,” “target,” “likely,” “will,” “to be” or other 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. These factors are difficult to accurately predict and may be beyond our control. Factors that could affect our results or an investment in our securities include, but are not limited to:

Factors related to our Chapter 11 Cases (as defined herein)

our ability to consummate the Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession, dated January 27, 2017 (as further modified, the Plan) as confirmed by an order of the Bankruptcy Court entered on March 17, 2017;

the effects of the Chapter 11 Cases on our operations, including customer, supplier, banking, insurance and other relationships and agreements;

- Bankruptcy Court rulings in the Chapter 11 Cases as well as the outcome of all other pending litigation and the outcome of the Chapter 11 Cases in general;

the length of time that we will operate under Chapter 11 protection and the continued availability of operating capital during the pendency of the proceedings;

the risks associated with third-party motions in the Chapter 11 Cases, which may interfere with our ability to consummate the Plan and restructuring generally;

increased advisory costs to execute a plan of reorganization;

the volatility of the trading price of our common stock and the absence of correlation between any increases in the trading price and our expectation that the common stock will be canceled and extinguished upon the Plan's effective date (Plan Effective Date);

the risk that the Plan does not become effective, in which case there can be no assurance that the Chapter 11 Cases will continue rather than be converted to Chapter 7 liquidation cases or that any alternative plan of reorganization would be on terms as favorable to holders of claims and interests as the terms of the Plan;

Peabody Energy’s ability to use cash collateral and the possibility that Peabody Energy may be required to post additional cash collateral to secure its obligations;

the effect of the Chapter 11 Cases on our relationships with third parties, regulatory authorities and employees;

the potential adverse effects of the Chapter 11 Cases on our liquidity, results of operations, or business prospects;

our ability to execute our business and restructuring plan;

increased administrative and legal costs related to the Chapter 11 Cases and other litigation and the inherent risks involved in a bankruptcy process;

the cost, availability and access to capital and financial markets, including the ability to secure new financing after emerging from the Chapter 11 Cases; and

the risk that the Chapter 11 Cases will disrupt or impede our international operations, including our business operations in Australia.

Other factors

- competition in the energy market and supply and demand for our coal products, including the impact of alternative energy sources, such as natural gas and renewables;
 - global steel demand and the downstream impact on metallurgical coal prices, and lower demand for our products by electric power generators;
 - our ability to successfully consummate planned divestitures, including the planned sale of all of our equity interests in Metropolitan Collieries Pty Ltd, the entity that owns the Metropolitan coal mine in New South Wales, Australia (the Metropolitan Mine);
 - our ability to appropriately secure our requirements for reclamation, federal and state workers' compensation, federal coal leases and other obligations related to our operations, including our ability to utilize self-bonding and/or successfully access the commercial surety bond market;
 - customer procurement practices and contract duration;
 - the 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, bank 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;
 - effects of changes in interest rates and currency exchange rates (primarily the Australian dollar);
 - effects of acquisitions or divestitures;
 - economic strength and political stability of countries in which we have operations or serve customers;
 - legislation, regulations and court decisions or other government actions, including, but not limited to, new environmental and mine safety requirements, changes in income tax regulations, sales-related royalties, or other regulatory taxes and changes in derivative 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;
 - terrorist attacks or security threats, including, but not limited to, cybersecurity breaches;
 - and
 - impacts of pandemic illnesses.
- Factors related to our indebtedness and expected post-emergence capital structure under the Plan
- the fact that our common stock will be canceled and extinguished upon the Plan Effective Date, if the Plan becomes effective, with no payments made to the holders of our common stock;
 - the lack of an established market for the shares of new common stock (Reorganized PEC Common Stock) or the preferred stock (Preferred Equity) to be issued pursuant to the Plan on the Plan Effective Date, and potential dilution of Reorganized PEC Common Stock due to future issuances of equity securities;
 - our ability to generate sufficient cash to service all of our expected post-emergence indebtedness;
 - our post-emergence debt instruments and capital structure will place certain limits on our ability to pay dividends and repurchase common stock;
 - our ability to comply with financial and other restrictive covenants in various agreements, including the credit facility contemplated by the Plan; and
 -

other risks and factors, including those discussed in "Legal Proceedings," set forth Part I, Item 3 of this report and "Risk Factors," set forth in Part I, Item 1A of this report.

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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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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. We own interests in 23 coal mining operations located in the United States (U.S.) and Australia. We have previously reported owning interests in 25 mining operations, but have combined the Somerville North Mine with the Somerville Central Mine, and the Somerville South Mine with the Wild Boar Mine (all part of our Midwestern operating segment) to create more efficient mining complexes, which reduces our reported number of operations by two. We have a majority interest in 22 of those mining operations and a 50% equity interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. In addition to our mining operations, we market and broker coal from other coal producers, both as principal and agent, and trade coal and freight-related contracts through trading and business offices in Australia, China, Germany, the United Kingdom and the U.S. (listed alphabetically).

History and Development

We were incorporated in Delaware in 1998 and became a publicly traded company in 2001. Our history in the coal business dates back to 1883. In 2016, we achieved a global safety incidence rate of 1.22 incidents per 200,000 hours worked, marking a new company record, and a 35% improvement in our global safety performance over the past five years. We were also recognized by the U.S. National Mining Association as the first in the industry to achieve independent certification under the CORESafety® system.

Filing Under Chapter 11 of the United States Bankruptcy Code

On April 13, 2016 (the Petition Date), Peabody and a majority of its wholly owned domestic subsidiaries as well as one international subsidiary in Gibraltar (the Filing Subsidiaries, and together with Peabody, the Debtors) filed voluntary petitions for reorganization (the petitions collectively, the Bankruptcy Petitions) under Chapter 11 of Title 11 of the U.S. Code (the Bankruptcy Code) in the United States Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). The Company’s Australian operations and other international subsidiaries are not included in the filings. The Debtors' Chapter 11 cases (collectively, the Chapter 11 Cases) are being jointly administered under the caption *In re Peabody Energy Corporation, et al.*, Case No. 16-42529 (Bankr. E.D. Mo.). The Debtors continue to operate their business as “debtors-in-possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. In general, as debtors-in-possession, the Debtors are authorized under Chapter 11 to continue to operate as an ongoing business, but may not engage in transactions outside the ordinary course of business without the prior approval of the Bankruptcy Court.

On January 27, 2017, we filed with the Bankruptcy Court the Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, the Plan). Subsequently, the Debtors solicited votes on the Plan. On March 15, 2017, the Debtors filed a revised version of the Plan. On March 16, 2017, the Bankruptcy Court held a hearing to determine whether the Plan should be confirmed. On March 17, 2017, the Bankruptcy Court entered an order confirming the Plan.

Although the Bankruptcy Court has confirmed the Plan, the Debtors have not yet consummated all of the transactions that are contemplated by the Plan. Rather, the Debtors intend to consummate these transactions in the near future, on or before the Plan Effective Date. As set forth in the Plan, there are certain conditions precedent to the occurrence of the Plan Effective Date, which must be satisfied or waived in accordance with the Plan in order for the Plan to become effective and the Debtors to emerge from the Chapter 11 Cases. The Debtors anticipate that each of these conditions will be either satisfied or waived by early April 2017, which is the target for the Debtors' emergence from the Chapter 11 Cases. On the Plan Effective Date, the Debtors will, generally, no longer be governed by the Bankruptcy Court's oversight.

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Under the Plan, current holders of our equity securities will not receive any distributions, and the equity securities will be canceled upon the Plan Effective Date. Accordingly, we urge that caution be exercised with respect to existing and future investments in our equity or other securities. Additional information about our Chapter 11 Cases is available on the Internet at www.peabodyenergy.com. Bankruptcy Court filings, claims information and our Plan are available at www.kccllc.net/peabody. Information contained on these websites is not part of, and is not incorporated by reference in, this Form 10-K.

Segment and Geographic Information

We conduct business through six operating segments: Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining, Australian Metallurgical Mining, Australian Thermal Mining and Trading and Brokerage. Segment and geographic financial information is contained in Note 29. "Segment and Geographic Information" to our consolidated financial statements and is incorporated herein by reference.

Mining Segments

U.S. Mining Operations - Powder River Basin, Midwestern, Western

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 as international exports as 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 sulfur content and Btu 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, coal with a mid-range sulfur content and Btu. 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 U.S. Mining operations mine both bituminous and sub-bituminous coal deposits.

Australian Mining Operations - Metallurgical, Thermal

The business of our Australian operating platform is primarily export focused with customers spread across several countries, while a portion of our metallurgical and 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 coking coal and low-volatile pulverized coal injection (LV 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, we may market some of our metallurgical coal products as a thermal coal product from time to time depending on supply and demand conditions.

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The table below summarizes information regarding the operating characteristics of each of our mines that were active in 2016 in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2016.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Primary Transport Method	2016 Tons Sold (In millions)
Powder River Basin Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	92.9
Caballo	Wyoming	S	D, T/S	T	R	11.2
Rawhide	Wyoming	S	D, T/S	T	R	8.1
Third party ⁽¹⁾	—	—	—	—	—	0.9
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	Tr, R	7.4
Wild Boar	Indiana	S	D, T/S	T	Tr, R, R/B, T/B	2.7
Somerville Central	Indiana	S	DL, D, T/S	T	R, R/B, T/B, T/R	2.4
Francisco Underground	Indiana	U	CM	T	R	2.1
Gateway North	Illinois	U	CM	T	Tr, R, R/B, T/B	1.8
Wildcat Hills Underground	Illinois	U	CM	T	T/B	1.6
Cottage Grove	Illinois	S	D, T/S	T	T/B	0.3
Western U.S. Mining						
Kayenta	Arizona	S	DL, T/S	T	R	5.8
El Segundo	New Mexico	S	D, DL, T/S	T	R	4.9
Twentymile	Colorado	U	LW	T	R, Tr	2.6
Lee Ranch	New Mexico	S	T/S	T	R	0.4
Australian Metallurgical Mining						
Millennium	Queensland	S	D, T/S	M, P	R, EV	3.8
Coppabella ⁽²⁾	Queensland	S	DL, D, T/S	P	R, EV	2.4
Metropolitan ⁽³⁾	New South Wales	U	LW	M	R, EV	2.0
Moorvale ⁽²⁾	Queensland	S	D, T/S	P	R, EV	1.9
Burton* ⁽⁴⁾	Queensland	S	DL, T/S	M, T	R, EV	1.7
North Goonyella ⁽⁵⁾	Queensland	U	LW, LTCC	M	R, EV	1.6
Middlemount ⁽⁶⁾	Queensland	S	D, T/S	M, P	R, EV	—
Australian Thermal Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	14.1
Wambo Open-Cut ⁽⁷⁾	New South Wales	S	T/S	T	R, EV	3.7
Wambo Underground ⁽⁷⁾	New South Wales	U	LW	M, T	R, EV	3.5
Legend:		R	Rail			
S	Surface Mine	Tr	Truck			
U	Underground Mine	R/B	Rail to Barge			
DL	Dragline	T/B	Truck to Barge			
D	Dozer/Casting	T/R	Truck to Rail			
T/S	Truck and Shovel	EV	Export Vessel			
LW	Longwall	T	Thermal/Steam			
LTCC	Longwall Top Coal Caving	M	Metallurgical			
CM	Continuous Miner	P	Pulverized Coal Injection			

* Mine operated by a contract miner

⁽¹⁾ Third party purchased coal used to satisfy certain specific coal supply agreements.

- (2) We own a 73.3% undivided interest in an unincorporated joint venture that owns the Coppabella and Moorvale mines.
On November 3, 2016, we entered into a definitive share sale and purchase agreement (SPA) for the sale of all of our equity interest in the Metropolitan Mine to a subsidiary of South32 Limited (South32). The closing of the transaction is conditional upon receipt of approval from the Australian Competition and Consumer Commission (ACCC). On February 22, 2017, the ACCC issued a Statement of Issues relating to the transaction, noting that the
- (3) ACCC is continuing to review the transaction. On February 24, 2017, pursuant to its right under the SPA, South32 extended the CP End Date (as defined in the SPA) from March 3, 2017 to April 17, 2017. On March 21, 2017, the ACCC notified us that it has extended the date on which it intends to render its decision regarding the transaction to April 27, 2017, which date extends beyond the CP End Date. As a result, we are assessing our options under the SPA.
- (4) Mine status changed to care and maintenance during 2016 and operations ceased.
- (5) A significant geological event has resulted in the cessation of the longwall top coal caving system, which will result in the mine operating conventional longwall equipment for at least the remainder of the current panel.
We own a 50% equity interest in Middlemount, which owns the Middlemount Mine. Because that entity is
- (6) accounted for as an unconsolidated equity affiliate, 2016 tons sold from that mine, which totaled 4.5 million tons (on a 100% basis), have been excluded from the table above.
- (7) Represents our majority-owned mines in which there is an outside non-controlling ownership interest.

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

Trading and Brokerage Segment

Our Trading and Brokerage segment engages in the direct and brokered trading of coal and freight-related contracts through 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, including optimization and blending of such coal, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. Our Trading and Brokerage segment also provides transportation-related services, which involves both financial derivative contracts and physical contracts. Collectively, coal and freight-related hedging activities include both economic hedging and, 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, including our shared services functions, 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, 2016, we controlled approximately 5.6 billion tons of proven and probable coal reserves and approximately 600,000 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. These surface lands include acres where we have completed post-mining reclamation. 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, 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 2016. During the years ended December 31, 2016, 2015 and 2014, the mine sold 4.5 million, 4.2 million and 3.7 million tons of coal, respectively (on a 100% basis).

U.S. 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 Europe and Brazil. On January 30, 2017, the Bankruptcy Court issued an order authorizing certain subsidiaries of the Company to enter into a stalking horse purchase agreement and approved bidding procedures for the sale of this interest. Pursuant to that order, the deadline to submit qualified bids for the purchase of this interest was set for March 2, 2017 at 4:00 p.m. (Central) and the related auction was scheduled to begin on March 6, 2017 at 10:00 a.m. (Central). On February 10, 2017, Contura Terminal and Ashland Terminal, Inc., both of which are partners of the Dominion Terminal Associates partnership, filed an appeal of the January 30, 2017 order. On March 6, 2017, the Company held the auction relating to the sale of this interest. At the auction, Contura Terminal, LLC and Ashland Terminal, Inc., who bid at the auction together, were declared the successful bidder. On March 7, 2017, the Company filed a notice with the Bankruptcy Court indicating the identity of the successful bidder. On March 9, 2017, the Bankruptcy Court entered an order approving the sale of the Company's interest in Dominion Terminal Associates to Contura Terminal, LLC and Ashland Terminal, Inc. On March 14, 2017, the Bankruptcy Appellate Panel for the Eighth Circuit entered an order dismissing the appeal of Contura Terminal, LLC and Ashland Terminal, Inc. to the Bankruptcy Court's January 26, 2017 order. The sale of the Company's interest in Dominion Terminal Associates is expected to close prior to the Plan Effective Date.

Clean Coal Technology. We continue to advocate for policies in support of clean coal technology development and initiatives seeking to be more energy efficient and reduce global atmospheric levels of carbon dioxide and other

emissions.

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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 and brokerage transactions) are made under long-term coal supply agreements (those with initial terms of one year or longer 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 86%, 88% and 83% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2016, 2015 and 2014, respectively. A recent trend has been for our customers under long-term coal supply agreements to seek contracts of shorter duration.

For the year ended December 31, 2016, we derived 28% of our total revenues from our five largest customers. Those five customers were supplied primarily from 24 coal supply agreements (excluding trading and brokerage transactions) expiring at various times from 2017 to 2026. The contract contributing the greatest amount of annual revenue in 2016 was approximately \$250 million, or approximately 5% of our 2016 total revenues, and is due to expire in 2026.

Backlog. Our sales backlog (excluding trading and brokerage transactions), which includes coal supply agreements subject to price reopener and/or extension provisions, was approximately 587 million and 690 million tons of coal as of January 1, 2017 and 2016, respectively. Contracts in backlog have remaining terms ranging from one to 12 years and represent approximately three years of production based on our 2016 production volume of 175.6 million tons. Approximately 72% of our backlog is expected to be filled beyond 2017.

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 59%, 63% and 59% of our total revenue base for the years ended December 31, 2016, 2015 and 2014, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 81%, 83% and 83% 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 41%, 36% and 39% of our total revenue base for the years ended December 31, 2016, 2015 and 2014, respectively, during which periods the coal mining activities of those segments contributed respective amounts of 19%, 17% and 17% 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, port 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%, 0% and 1% of its annual tons sold for the years ended December 31, 2016, 2015 and 2014, 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.

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Our Australian Mining operations sold approximately 75%, 77% and 77% of its tons into the seaborne coal markets for the years ended December 31, 2016, 2015 and 2014, 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.

In the past, there has been consolidation in the supplier base providing certain mining materials and equipment to the coal industry. This has limited the number of global sources for these items, such as surface and underground mining equipment. 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 extend the lives of existing equipment through improved maintenance practices and equipment rebuilds in order to defer the requirement for larger capital purchases. We continue to use our global leverage with major suppliers to ensure security of supply to meet the requirements of our active mines.

Services. We also purchase services at our mine sites, including services related to maintenance for mining equipment, construction, temporary labor, use of explosives and various other requirements. We do not believe that we have undue operational or financial risk associated with our dependence on any individual service providers.

Competition

Demand for coal and the prices that we will be able to obtain for our coal are highly competitive and influenced by factors beyond our control, including but not limited to global economic conditions, the demand for electricity and steel, the cost of alternative fuels, the cost of electricity generation from alternative fuels, including wind, solar, oil, hydro, nuclear, natural gas and biomass, the impact of weather on heating and cooling demand and taxes and environmental regulations imposed by the U.S. and foreign governments.

Thermal Coal

Demand for our thermal coal products is impacted by economic conditions and demand for electricity and the cost of electricity generation from coal and alternative fuels, and our products compete with producers of other forms of electric generation, including natural gas, oil, nuclear, hydro, wind, solar and biomass, that provide an alternative to coal use. The use and price of thermal coal is heavily influenced by the availability and relative cost of alternative fuels and the generation of electricity utilizing alternative fuels, with customers focused on securing the lowest cost fuel supply in order to coordinate the most efficient utilization of generating resources in the economic dispatch of the power grid at the most competitive price.

In the U.S., natural gas is highly competitive (along with other alternative fuel sources) with thermal coal for electricity generation. The competitiveness of natural gas has been strengthened by accelerated growth in domestic

natural gas production and transmission facilities over the last five years and comparatively low natural gas prices (versus historic levels). In 2016, electricity generation from coal was negatively impacted primarily by low-priced natural gas, which fell to an average price of \$2.55 per mmBtu, as well as by the relatively mild temperatures in the first half of 2016 that reduced overall electricity demand. Gas prices averaged \$2.12 per mmBtu in the first half of 2016, and \$2.98 per mmBtu in the second half of 2016. These natural gas price trends significantly impacted U.S. coal burn and production in 2016, where major producers' shipments in the second half of 2016 were substantially higher than in the first half. We believe the U.S. Powder River and Illinois basins in which we produce are competitive against natural gas when natural gas prices are in excess of \$3.00 per mmBtu. In addition, the competitiveness of other alternative fuel sources for electricity generation with coal has been strengthened by the growth of low-cost generation fueled by other alternative fuel sources.

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Internationally, thermal coal also competes with alternative forms of electric generation. The competitiveness and availability of natural gas, oil, nuclear, hydro, wind, solar and biomass varies by country and region. In addition, seaborne thermal coal import demand can be significantly impacted by the availability of indigenous coal production, particularly in the two leading coal import countries, China and India, among others, and the competitiveness of seaborne supply from leading thermal coal exporting countries, including Indonesia, Australia, Russia, Colombia and South Africa, among others.

In addition to our alternative fuel source competitors, 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., Cloud Peak Energy Inc., and Murray Energy Corporation, which collectively accounted for approximately 42% of total U.S. coal production in 2015 according to the National Mining Association's "2015 Coal Producer Survey," the most recent data publicly available as of March 20, 2017. Major international direct coal supply competitors (listed alphabetically) include Anglo-American PLC, BHP Billiton, China Coal, Coal India Limited, Glencore PLC, PT Bumi Resources Tbk., Rio Tinto and Shenhua Group, among others.

Metallurgical Coal

Demand for our metallurgical coal products is impacted by economic conditions and demand for steel, and 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.

Seaborne metallurgical coal import demand can be significantly impacted by the availability of indigenous coal production, particularly in leading metallurgical coal import countries of China, India, Japan, South Korea and Brazil, among others, and the competitiveness of seaborne metallurgical coal supply, including from leading metallurgical coal exporting countries of Australia, U.S., Russia, Canada, and Mongolia, among others.

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, among others.

Working Capital

We generally fund our working capital requirements through a combination of existing cash and cash equivalents, proceeds from the sale of our coal production to customers and our trading and brokerage activities. Our current accounts receivable securitization program is also available to fund our working capital requirements to the extent we have remaining availability under the program. On January 27, 2017, we obtained a commitment letter (Commitment Letter) from PNC Bank, National Association (PNC), pursuant to which PNC has agreed to amend and restate our existing securitization program effective as of the Plan Effective Date to, among other things, provide for the exit from the Chapter 11 Cases, add certain Australian subsidiaries as originators, extend the termination date to three years from the Plan Effective Date and increase the maximum funding limit to up to \$250 million (subject to reductions prior to the Plan Effective Date to an amount no less than \$200 million). PNC's obligation to provide the new securitization program is also subject to a number of customary conditions precedent. On February 15, 2017, the Bankruptcy Court issued an order authorizing the Company's entry into and performance under the Commitment Letter. Refer to the "Liquidity and Capital Resources" section of Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding working capital.

Employees

We had approximately 6,700 employees as of December 31, 2016, including approximately 5,100 hourly employees. Additional information on our employees and related labor relations matters is contained in Note 24. "Management - Labor Relations" to our consolidated financial statements, which information is incorporated herein by reference.

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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	49	President and Chief Executive Officer
Amy B. Schwetz	42	Executive Vice President and Chief Financial Officer
A. Verona Dorch	50	Executive Vice President, Chief Legal Officer, Government Affairs and Corporate Secretary
Bryan A. Galli	56	Group Executive of Marketing and Trading
Charles F. Meintjes	54	President - Australia
Kemal Williamson	57	President - Americas

⁽¹⁾ As of March 15, 2017.

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, holds a master's degree in business administration and a bachelor's degree in commerce from the University of Newcastle, and is a Fellow of CPA Australia. 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.

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 legal and government relations 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, Chief Compliance Officer and Corporate Secretary. Ms. Dorch also has experience in corporate and securities law from various law firms and with Sumitomo Chemical Co. Ms. Dorch holds a bachelor's degree from Dartmouth College and a Juris Doctor degree from Harvard Law School.

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

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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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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.

On March 15, 2017, we announced that Mr. Meintjes will assume the role of Executive Vice President - Corporate Services and Chief Commercial Officer effective following our emergence from our Chapter 11 Cases and George J. Schuller, the current Chief Operations Officer in Australia, will fill the role of President - Australia.

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.

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.

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.

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 MSHA compliance, through the mine safety disclosures required by SEC regulations.

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Black Lung (Coal Worker's Pneumoconiosis)

Under the U.S. 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 who last worked for the operator after July 1, 1973, and whose claims for benefits are allowed. 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, very few of the miners who sought federal black lung benefits were 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 underground 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 primary regulatory authority, with oversight from OSM. 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.

SMCRA provides for three categories of bonds: surety bonds, collateral bonds and self-bonds. A surety bond is an indemnity agreement in a sum certain payable to the regulatory authority, executed by the permittee as principal and which is supported by the performance guarantee of a surety corporation. A collateral bond can take several forms, including cash, letters of credit, first lien security interest in property or other qualifying investment securities. A self-bond is an indemnity agreement in a sum certain executed by the permittee or by the permittee and any corporate guarantor made payable to the regulatory authority.

Our total reclamation bonding requirements in the U.S. were \$1,413.8 million as of December 31, 2016. The bond requirements for a mine represent the calculated cost to reclaim the current operations of a mine if it ceased to operate in the current period. The cost calculation for each bond must be completed according to the regulatory authority of each state. Our asset retirement obligations calculated in accordance with generally accepted accounting principles for our U.S. operations were \$471.1 million as of December 31, 2016. The bond requirement amount for our U.S. operations significantly exceeds the financial liability for final mine reclamation because the asset retirement obligation liability is discounted from the end of the mine's economic life to the balance sheet date in recognition that the final reclamation cash outlay is a number of years (and in some cases decades) away. The bond amount, in contrast with the asset retirement obligation, presumes reclamation begins immediately.

As a condition precedent to the occurrence of the Effective Date of the Plan, we were required to put in place mutually acceptable forms of bonding for coal mine reclamation requirements in Wyoming, New Mexico, Illinois and Indiana subsequent to the Effective Date. On March 6, 2017, we notified the Bankruptcy Court that we had determined to secure all our coal mine reclamation obligations, including those in Wyoming, New Mexico, Illinois and Indiana, by arranging for approximately \$1.3 billion in surety bonds.

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 bonding requirements.

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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.

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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 based on changes in federal legislation. 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. We recognized expense related to the fees of \$38.7 million, \$47.0 million and \$50.5 million for the years ended December 31, 2016, 2015 and 2014, 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, designating new nonattainment areas or expanding existing nonattainment areas, requiring changes in vehicle emission standards or prompting additional local control measures pursuant to state implementation plans required to address revised NAAQS.

In recent years the United States Environmental Protection Agency (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. The EPA subsequently issued a final rule setting the ozone standard at 70 parts per billion (ppb). (80 Fed. Reg. 65,292, (Oct. 25, 2015)). This final rule has been challenged in the United States Court of Appeals for the D.C. Circuit (D.C. Circuit) and the oral argument is scheduled for April 19, 2017. More stringent ozone standards require new state implementation plans to be developed and filed with the EPA, may trigger additional control technology for mining equipment, or result in additional challenges to permitting and expansion efforts.

In 2009, the EPA also adopted revised rules to add more stringent PM emissions limits for coal preparation and processing plants constructed or modified after April 28, 2008. The PM NAAQS was thereafter revised and made more stringent. The D.C. Circuit subsequently upheld the revised PM NAAQS (*National Association of Manufacturers v. EPA*, Nos. 13-1069, 13-1071 (May 9, 2014)). In addition, since 2011, the EPA has required underground coal mines to report on their greenhouse gas emissions.

The CAA also indirectly, but 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, imposing more capital and operating costs on such facilities. In addition, other CAA programs may require further emission reductions to address the interstate transport of air pollution or regional haze. 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 such as the Cross-State Air Pollution Rule, New Source Performance Standards (NSPS), Maximum Achievable Control Technology (MACT) emissions limits for Hazardous Air Pollutants, the Regional Haze program and source permitting programs, including requirements related to New Source Review.

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 CO₂/MWh-gross. The standard is based on the performance of a supercritical pulverized coal boiler implementing partial carbon capture, utilization and storage (CCUS). Modified and reconstructed fossil fuel-fired steam generating units must implement the most efficient generation achievable through a combination of

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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 CO₂/MWh-gross, and subcritical conditions for smaller units to meet a standard of 2,000 lb CO₂/MWh-gross.).

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Numerous legal challenges to the final rule have been filed in the 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. Four additional cases were filed seeking review of the EPA's denial of reconsideration petitions in a final action published in the May 6, 2016 Federal Register entitled "Reconsideration of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units; Notice of final action denying petitions for reconsideration." States and other organizations have intervened on behalf of the EPA. Upon petitioners' request, the D.C. Circuit suspended the briefing schedule and consolidated the challenges to the EPA's denial of petitions for reconsideration with the previously filed North Dakota case. On August 30, 2016, the Court entered a briefing schedule under which final briefs were due February 6, 2017. Oral arguments have been scheduled for April 17, 2017.

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 were required to submit their proposed implementation plans to the EPA by September 6, 2016, unless an extension was 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 reduce 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 acknowledged that a legal challenge could be filed after the EPA issued a final rule. In September 2015 the D.C. Circuit refused to stay the rule, holding that it could not review the rule until it was published in the Federal Register which occurred on October 23, 2015.

Following Federal Register publication of the rule on October 23, 2015, 39 separate petitions for review by approximately 157 entities were filed in 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 the EPA.

On January 21, 2016, the D.C. Circuit 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 stay 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. The stay provides that, if a writ of certiorari is sought and the Supreme Court denies the petition, the stay will terminate automatically. The stay also provides that, if the Supreme Court grants the petition for a writ of certiorari, the stay will terminate when the Supreme Court enters its judgment. Briefing on the merits of the petitions for review in the D.C. Circuit has concluded. The case was heard en banc by ten active D.C. Circuit judges on September 27, 2016.

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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 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 the 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 the 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. The 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.

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 held on July 28, 2015 that certain of the 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. The EPA indicated that this rule was a “partial response” to the D.C. Circuit’s remand of CSAPR as well as to address implementation of the 2008 ozone NAAQS. This rule, known as the CSAPR Update Rule, was signed by the EPA Administrator on September 7, 2016. The CSAPR Update Rule implements further reductions in nitrogen oxides in 2017 in 22 states subject to CSAPR during the summertime ozone season. The EPA did not address other aspects of the remand involving the CSAPR budgets for sulfur dioxide in four states. Several states and utilities as well as agricultural and industry groups utilities have filed petitions for review of the CSAPR Update Rule in the D.C. Circuit. Other states and interest groups have filed to intervene on behalf of the EPA. These petitions have been consolidated under D.C. Cir. No. 16-1406.

Mercury and Air Toxic Standards (MATS). The EPA published the final MATS rule in the Federal Register on February 16, 2012. The MATS rule revised the NSPS for nitrogen oxides, sulfur dioxides and particulate matter for

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On April 14, 2016, the EPA issued a final supplemental finding that largely tracked its proposed finding. Several states, companies and industry groups challenged that supplemental finding in the D.C. Circuit in separate petitions for review, which were subsequently consolidated. Several states and environmental groups also filed as intervenors for the respondent EPA. Briefing commenced in December 2016 and has now concluded. Oral argument has been scheduled for May 18, 2017.

Stream Protection Rule. On July 27, 2015, the OSM issued its proposed Stream Protection Rule (SPR). The proposed rule would have impacted both surface and underground mining operations and would have increased testing and monitoring requirements related to the quality or quantity of surface water and groundwater or the biological condition of streams. The SPR would have also required 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. Both chambers of Congress have already passed legislation to repeal and invalidate the rulemaking, pursuant to the Congressional Review Act. The House passed H.J. Res. 38 on February 1, 2017 and the Senate passed the bill the next day. On February 16, 2017, President Trump signed H.J. Res. 38, resulting in the repeal of the SPR and preventing the OSMRE from promulgating any substantially similar rule.

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.

A final rule defining the scope of waters protected under the Clean Water Act (commonly called the Waters of the United States (WOTUS) Rule) was published by the EPA and the Corps in June 2015. Numerous lawsuits were filed in district courts and courts of appeals nationwide, and all courts of appeals challenges were consolidated in the U.S. Court of Appeals for the Sixth Circuit. District courts in Oklahoma and Georgia dismissed challenges for lack of jurisdiction, but a preliminary injunction was issued by the U.S. District Court in North Dakota in August 2015. On October 9, 2015, the Sixth Circuit stayed the WOTUS Rule nationwide pending further action of the court. On February 22, 2016, a three member panel of the Sixth Circuit held that the Sixth Circuit has exclusive jurisdiction to review challenges to the rule. A request for an en banc hearing was denied. The Tenth and Eleventh Circuits, which are presiding over appeals of the dismissals from Oklahoma and Georgia (respectively), have since stayed proceedings in those appeals. On October 7, 2016, several industry trade organizations and associations filed a petition requesting that the U.S. Supreme Court review the decision of the Sixth Circuit to exercise exclusive jurisdiction over challenges to the rule. The petition was granted on January 13, 2017. Since the Supreme Court agreed to take the case, it has extended the briefing schedule and postponed oral argument until late 2017 at the earliest. On February 28, 2017 the Trump Administration released an Executive Order directing the EPA and the Corps to consider rescinding or revising the WOTUS Rule, and the EPA and the Corps issued a similar notice that same day. The Department of Justice has notified the courts of this development and has filed a motion in the Supreme Court to halt all proceedings. The Supreme Court is scheduled to consider all briefing on that motion during its March 31, 2017 conference.

Additionally, because the Sixth Circuit did not automatically halt its briefing schedule on the merits of the WOTUS Rule after the Supreme Court decided to hear the appeal of the jurisdictional decision, the industry coalition filed a petition asking the Sixth Circuit to do so. That petition was granted two days later and, as such, the Sixth Circuit

litigation is now being held in abeyance pending the Supreme Court's decision. Importantly, the Sixth Circuit's order holding the case in abeyance did not lift the current nationwide stay against implementation of the WOTUS Rule, and therefore the stay will remain effective during the Supreme Court's review, which could be held in abeyance if the Supreme Court grants the Department of Justice's recent motion. 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.

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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 (CCR or 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 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.

Office of Surface Mining Reclamation and Enforcement Self-Bonding Notice of Rulemaking. On August 16, 2016, the Office of Surface Mining Reclamation and Enforcement (OSMRE) announced a decision to initiate a rulemaking process to update OSMRE's bonding regulations. The decision stated that the OSMRE will be reviewing the self-bonding program and will consider revising the review process for determining if a company qualifies for self-bonding as well as the process for replacing self-bonds in the event a company no longer qualifies for self-bonding. There is no anticipated timing for the proposed rule and it is unknown whether the new Director of OSMRE will continue with the proposed rulemaking.

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 was amended effective September 27, 2016 to include significant changes to the management of overlapping coal and coal seam gas tenements and the coordination of activities and access to private and public land. In November 2016, amendments to the EP Act and the Water Act 2000 became effective and facilitate regulatory scrutiny of the environmental impacts of underground water extraction during the operational phase of resource projects for all tenements yet to commence mineral extraction. The ‘Chain of Responsibility’ provisions of the EP Act, effective in April 2016, allow the regulator to issue an environmental protection order (EPO) to a related person of a company in two circumstances; (a) if an EPO has been issued to the company, an EPO can also be issued to a related person of the company (at the same time or later); or (b) if the company is a high risk company (as defined in the EP Act), an EPO can be issued to a related person of the company (whether or not an EPO has also been issued to the company). A guideline has been issued to provide more certainty to industry on the circumstances when an EPO may be issued.

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.

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Mining Rehabilitation (Reclamation). Mine reclamation is regulated by state specific legislation. As a condition of approval for mining operations, companies are required to progressively reclaim mined land and provide appropriate bonding to the relevant state government as a safeguard to cover the costs of reclamation in circumstances where mine operators are unable to do so. Self-bonding is not permitted. Our mines hold bonds with the relevant authorities which are calculated in accordance with current regulatory requirements. We operate in both the Queensland and New South Wales state jurisdictions.

Our reclamation bonding requirements in Australia were \$379.4 million Australian dollars as of December 31, 2016. The bond requirements represent the calculated cost to reclaim the current operations of a mine if it ceased to operate in the current period less any discounts agreed with the state. The cost calculation for each bond must be completed according to the regulatory authority of each state. The costs associated with our Australian asset retirement obligations are calculated in accordance with generally accepted accounting principles and were \$287.7 million as of December 31, 2016. The total bonding requirements for our Australian operations differ from the calculated costs associated with the asset retirement obligations because the costs associated with asset retirement obligations are discounted from the end of the mine's economic life to the balance sheet date in recognition of the economic reality that reclamation is conducted progressively and final reclamation is a number of years (and in some cases decades) away, whereas the bonding amount represents the cost of reclamation if a mine ceases to operate immediately.

New South Wales reclamation. The Mining Act 1992 (Mining Act) is administered by the Department of Industry - Resources & Energy and authorizes the holder of a mining tenement to extract a mineral subject to obtaining consent under the Environmental Planning & Assessment Act 1979 and other auxiliary approvals and licenses.

Through the Mining Act, environmental protection and reclamation are regulated by conditions in all mining leases including requirements for the submission of a Mining Operations Plan (MOP) prior to the commencement of operations. All mining operations must be carried out in accordance with the MOP which describes site activities and the progress toward environmental and reclamation outcomes and are updated on a regular basis or if mine plans change. The mines publicly report their reclamation performance on an annual basis.

In support of the MOP process, a reclamation cost estimate is calculated periodically to determine the amount of bond support required to cover the cost of reclamation based on extent of disturbance during the MOP period.

Queensland reclamation. The Environmental Protection Act 1994 (EP Act) is administered by the Department of Environment and Heritage Protection which authorizes environmentally relevant activities such as mining activities relating to a mining lease through an Environmental Authority (EA). Environmental protection and reclamation activities are regulated by conditions in the EA, including the requirement for the submission of a Plan of Operations (PO) prior to the commencement of operations. All mining operations must be carried out in accordance with the PO which describes site activities and the progress toward environmental and rehabilitation outcomes and are updated on a regular basis or if mine plans change. The mines submit an annual return reporting on their EA compliance including reclamation performance.

As a condition of the EA, bonding requirements are calculated to determine the amount of bonding required to cover the cost of reclamation based on extent of disturbance during the PO period.

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.

A small number of coal mine workers in Queensland and New South Wales have been diagnosed with coal worker's pneumoconiosis (CWP, also known as black lung) following decades of assumed eradication of the disease. This has led the Queensland government to sponsor review of the system of screening coal mine workers for the disease with a view to improving early detection. The Queensland government has instituted increased reporting requirements for dust monitoring results, broader coal mine worker health assessment requirements and voluntary retirement examinations for coal mine workers to be arranged by the relevant employer and further reform may follow. Peabody has undertaken a review of its practices and offered its Queensland workers the opportunity for additional CWP

screening.

The Queensland government is holding a Parliamentary inquiry into the re-emergence of CWP in the State and is holding public hearings with representatives of the coal mining industry, including Peabody, coal mine workers, the Department of Natural Resources and others appearing. The inquiry is due to report to the Queensland Parliament in April 2017

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Industrial Relations. A national industrial relations system administered by the federal government applies to all private sector employers and employees. The 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 implemented the Emission Reduction Fund Safeguard Mechanism. From that date, large designated facilities such as coal mines were issued with a baseline for their covered emissions and must take steps to keep their emissions below the baseline or face penalties.

Queensland Royalty. Royalties are payable to the State of Queensland at a rate of 12.5% on coal prices over \$100 Australian dollars per tonne and up to \$150 Australian dollars per tonne and 15% on pricing over \$150 Australian dollars per tonne. The rate is 7% 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.

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 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. The 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. The EPA has also set standards applying to new, modified and reconstructed sources beginning in 2015.

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 mid-western states (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) and one Canadian province have entered into the Midwestern Regional Greenhouse Gas Reduction Accord (MGGRA) to establish voluntary regional greenhouse gas reduction targets and develop a voluntary multi-sector cap-and-trade system to help meet the targets. It has been reported that, while the MGGRA has not been formally suspended, the participating states are no longer pursuing it. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces entered

into the Western Climate Initiative (WCI) in 2008 to establish a voluntary regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. However, in November 2011, the WCI announced that six states had withdrawn from the WCI, leaving California and four Canadian provinces as the remaining members. Of those five jurisdictions, only California and Quebec have adopted greenhouse gas cap-and-trade regulations to date and both programs have begun operating. Many of the states and provinces that left WCI, RGGI and MGGRA, along with many that continue to participate, have joined the new North America 2050 initiative, which seeks to reduce greenhouse gas emissions and create economic opportunities in ways not limited to cap-and-trade programs.

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In the U.S., several states have enacted legislation establishing greenhouse gas emissions reduction goals or requirements. In addition, several states have enacted legislation or have in effect regulations requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power or that provide financial incentives to electricity suppliers for using renewable energy sources. Some states have initiated public utility proceedings that may establish values for carbon emissions. In Minnesota, an administrative proceeding recommended an approach based on the Federal Social Cost of Carbon to the Minnesota Public Utilities Commission. The Minnesota Public Utilities Commission will hold hearings on the recommendation in the first and second quarter of 2017. In 2016, the state of Washington considered Ballot Initiative 732, the "Washington Carbon Emission Tax and Sales Tax Reduction," which proposed to impose a new tax on carbon emissions beginning at \$15 per metric ton in 2017, and increasing each year until it reached \$100 per metric ton. The proposal was ultimately voted down in the November 8 election, with 60% opposed.

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 was entered into force on November 4, 2016 after ratification and execution by more than 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.

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 CCUS technologies and the alternative uses 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.

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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 Chapter 11 Cases

We are subject to risks and uncertainties associated with our Chapter 11 Cases.

On April 13, 2016 (Petition Date), we and a majority of our wholly owned domestic subsidiaries as well as one international subsidiary in Gibraltar (the Filing Subsidiaries, and together with Peabody, the Debtors) filed voluntary petitions for reorganization under Chapter 11 of Title 11 of the U.S. Code in the United States Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). Our Australian Operations are not included in the filings. Our Chapter 11 Cases are being jointly administered under the caption In re Peabody Energy Corporation, et al., Case No. 16-42529 (the Chapter 11 Cases). On January 27, 2017, the Debtors filed with the Bankruptcy Court the Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, the Plan). On March 15, 2017, the Debtors filed an amended version of the Plan, which was confirmed by the Bankruptcy Court by order entered March 17, 2017. There can be no assurance that the Plan will be implemented successfully. Until the Plan Effective Date, the Debtors will continue to operate the business as “debtors-in-possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

We are subject to a number of risks and uncertainties associated with the Chapter 11 Cases, which may lead to potential adverse effects on our liquidity, results of operations, condition (financial or otherwise), brand or business prospects. Our operations, our ability to develop and execute our business plan, our financial condition, our liquidity, and our continuation as a going concern, are all subject to the risks and uncertainties associated with our Chapter 11 Cases. These risks and uncertainties include, but are not limited to, the following:

- whether the conditions to consummate the transactions contemplated by the Plan will be satisfied or waived;
- our ability to comply with and operate under any cash management orders by the Bankruptcy Court from time to time;
- the high costs of Chapter 11 proceedings and related professional costs and fees;
- our ability to attract, motivate, and retain key personnel, especially in our current constrained compensation environment;
- our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- our ability to maintain critical contracts on reasonably acceptable terms and conditions;
- the ability of third parties to seek and obtain relief from the automatic stay to terminate contracts and other agreements with us;
- the actions and decisions of our creditors and other third parties who have interests in our Chapter 11 Cases that may be inconsistent with our plans;
 - our ability to self-bond or obtain adequate surety bonds with respect to our reclamation obligations, both during the Chapter 11 Cases and upon emergence from our Chapter 11 Cases; and
- the possibility that the Chapter 11 Cases will disrupt or impede our international operations, including our Australian Operations.

These risks and uncertainties could affect our business and operations in various ways. For example, negative events or publicity associated with our Chapter 11 Cases could adversely affect our relationships with our suppliers, vendors, customers, and employees. In particular, critical suppliers, vendors and customers may determine not to do business with us due to our Chapter 11 Cases, and we may not be successful in securing alternative sources or markets. Under Chapter 11 of the Bankruptcy Code, transactions outside the ordinary course of business are subject to the prior approval of the Bankruptcy Court, which may limit our ability to respond in a timely manner to certain events or take advantage of certain opportunities. Additionally, further losses of key personnel or erosion of employee morale could have a material adverse effect on our ability to meet customer expectations, thereby adversely affecting our business

and results of operations. The failure to retain or attract and maintain members of our management team, and other key personnel could impair our ability to execute our strategy and implement operational initiatives, thereby having a material adverse effect on our financial condition and results of operations. As a result of these risks and uncertainties, we cannot predict the ultimate impact that events occurring during the Chapter 11 Cases may have on our business, financial condition and results of operations, and there is no certainty as to our ability to continue as a going concern.

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The Plan may not become effective.

While the Plan has been confirmed by the Bankruptcy Court, it may not become effective because it is subject to the satisfaction of certain conditions precedent (some of which are beyond our control). There can be no assurance that such conditions will be satisfied, and therefore, that the Plan will become effective and that the Debtors will emerge from the Chapter 11 Cases as contemplated by the Plan. If the Plan Effective Date is delayed, the Debtors may not have sufficient cash available in order to operate their business. In that case, the Debtors may need new or additional post-petition financing, which may increase the costs of consummating the Plan. There is no assurance of the terms on which such financing may be available or if such financing will be available. If the transactions contemplated by the Plan are not completed, it may become necessary to amend the Plan. The terms of any such amendment are uncertain and could result in material additional expense and result in material delays in the Chapter 11 Cases.

If the Plan does not become effective, if current financing is insufficient, or if other financing is not available, we could be required to seek a sale of the Company or certain of its material assets pursuant to Section 363 of the Bankruptcy Code, or be required to liquidate under Chapter 7 of the Bankruptcy Code.

In order to successfully emerge from Chapter 11 bankruptcy protection, a plan of reorganization must become effective. There can be no assurance that the Plan Effective Date will occur, which would permit us to emerge from our Chapter 11 Cases and continue operations. If we are unable to meet our liquidity needs, we may have to take other actions to seek additional financing to the extent available or we could be forced to consider other alternatives to maximize potential recovery for the creditors, including possible sale of the Company or certain material assets pursuant to Section 363 of the Bankruptcy Code, or liquidate under Chapter 7 of the Bankruptcy Code.

There can be no assurance that our current cash position, as well as funds available from our accounts receivable securitization program, and amounts of cash from future operations, will be sufficient to fund ongoing operations during the Chapter 11 Cases. In the event that we do not have sufficient cash to meet our liquidity requirements, and our current financing is insufficient or exit financing is not available in connection with our emergence under a Chapter 11 plan of reorganization, we may be required to seek additional financing. There can be no assurance that such additional financing would be available, or, if available, would be available on reasonably acceptable terms. Failure to secure any necessary exit financing, or additional financing, would have a material adverse effect on our operations and ability to continue as a going concern.

Any plan of reorganization that we may implement will be based in large part upon assumptions and analyses developed by us. If these assumptions and analyses prove to be incorrect, or adverse market conditions persist or worsen, our plan may be unsuccessful in its execution.

Any plan of reorganization that we may implement, including the Plan, will affect our capital and the ownership and structure of our business, and will reflect assumptions and analyses based on our experience and perception of historical trends, current conditions, and expected future developments, as well as other factors that we consider appropriate under the circumstances. Whether actual future results and developments will be consistent with our expectations and assumptions depends on a number of factors, including but not limited to: (i) our ability to substantially change our capital structure; (ii) our ability to obtain adequate liquidity and financing sources; (iii) our ability to maintain customers' confidence in our viability as a continuing entity and to attract and retain sufficient business from them; (iv) our ability to retain key employees, and (v) the overall strength and stability of general economic conditions of the financial and coal industries, both in the U.S. and in global markets. The failure of any of these factors could materially and adversely affect the successful reorganization of our business.

In addition, any plan of reorganization, including the Plan, will rely upon financial projections, including with respect to revenues, Adjusted EBITDA, capital expenditures, debt service, cash flow and coal price projections. Financial projections are necessarily speculative, and it is likely that one or more of the assumptions and estimates that are the basis of these financial forecasts will not be realized. In our case, the forecasts will be even more speculative than normal, because they may involve fundamental changes in the nature of our capital structure. Accordingly, we expect that our actual financial condition and results of operations will differ, perhaps materially, from what we have anticipated. Consequently, there can be no assurance that the results or developments contemplated by any plan of reorganization we may implement will occur or, even if they do occur, that they will have the anticipated effects on us or our business or operations. The failure of any such results or developments to materialize as anticipated could

materially and adversely affect the successful execution of any plan of reorganization.

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Certain claims may not be discharged and could have a material adverse effect on our financial condition and results of operations.

The Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation. With few exceptions, all claims that arose prior to our filing a petition for reorganization under the Bankruptcy Code or before the confirmation of the Plan (a) were subject to compromise and/or treatment under the Plan and/or (b) will be discharged in accordance with the terms of the Plan on the Plan Effective Date. Any claims not ultimately discharged through the Plan could be asserted against us and may have an adverse effect on our financial condition and results of operations on a post-reorganization basis.

Operating in bankruptcy for a long period of time may harm our business.

Our future results will be dependent upon the successful implementation of a plan of reorganization. A long period of operations under Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations, and liquidity. So long as the proceedings related to these cases continue, senior management will be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on business operations. A prolonged period of operating under Bankruptcy Court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, the longer the proceedings related to the Chapter 11 Cases continue, the more likely it is that customers and suppliers will lose confidence in our ability to reorganize our business successfully and will seek to establish alternative commercial relationships.

So long as the proceedings related to these cases continue, we will be required to incur substantial costs for professional fees and other expenses associated with the administration of the Chapter 11 Cases, including the cost of litigation. In general, litigation can be expensive and time consuming to bring or defend against. Such litigation could result in settlements or damages that could significantly affect our financial results. It is also possible that certain parties will commence litigation with respect to the treatment of their claims under the Plan. It is not possible to predict the potential litigation that we may become party to, nor the final resolution of such litigation. The impact of any such litigation on our business and financial stability, however, could be material.

Should the Chapter 11 proceedings continue beyond our current targeted emergence date in early April 2017, we may also need to seek new financing to fund operations. If we are unable to obtain such financing on favorable terms or at all, the chances of successfully reorganizing our business may be seriously jeopardized and the likelihood that we will instead be required to liquidate our assets may increase.

As a result of the Chapter 11 Cases, our historical financial information will not be indicative of our future financial performance and realization of assets and liquidation of liabilities are subject to uncertainty.

Our capital structure will be significantly altered through the implementation of the Plan. As a result of the consummation of the Plan and the transactions contemplated thereby, we expect to be subject to the fresh start reporting rules required under the Financial Accounting Standards Board Accounting Standards Codification Topic 852, Reorganizations. Under applicable fresh start reporting rules that may apply to us upon the Plan Effective Date, our assets and liabilities would be adjusted to fair values and our accumulated deficit would be restated to zero.

Accordingly, our consolidated financial condition and results of operations from and after the Plan Effective Date will not be comparable to the financial condition or results of operations reflected in our consolidated historical financial statements.

In connection with the implementation of the Plan, it is also possible that additional restructuring and related charges may be identified and recorded in future periods. Such sales, disposals, liquidations, settlements, or charges could be material to our consolidated financial position and the results of operations in any given period.

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Our ability to use our pre-emergence tax attributes may be significantly limited under the U.S. federal income tax rules.

We have generated net operating losses and certain tax credits for U.S. federal income tax purposes (NOLs) through the taxable year ending December 31, 2016. We expect to incur substantial additional NOLs through the Plan Effective Date. Our NOLs and other tax attributes, including our tax basis in assets, are subject to reduction on account of cancellation of indebtedness income. Moreover, our ability to use any remaining NOLs and other tax attributes, and possibly any recognized built in losses, to offset future taxable income or taxes owed may be significantly limited if we undergo an “ownership change” as defined in section 382 of the Internal Revenue Code of 1986 as amended (the Code) in connection with the Plan and do not qualify or elect to use a special bankruptcy rule. An entity that experiences an ownership change generally is subject to an annual limitation on its use of its pre-ownership change NOLs and other tax attributes after the ownership change equal to the equity value of the corporation immediately before the ownership change, multiplied by the long term tax exempt rate posted by the Internal Revenue Service (subject to certain adjustments). If we undergo an ownership change in connection with the Plan, however, we will be allowed to calculate the limitation on NOLs and other tax attributes, in general, by reference to our equity value immediately after the ownership change (rather than the equity value immediately before the ownership change, as is the case under the general rule for non-bankruptcy ownership changes), thus generally reflecting any increase in the value of the stock due to the cancellation of debt resulting from the Plan. The annual limitation could also be increased each year to the extent that there is an unused limitation in a prior year. Alternatively, if we qualify for and elect to use a special bankruptcy rule that would prevent a limitation on use of the tax attributes from applying, our NOLs would first be reduced to the extent of certain prior interest deductions taken on account of indebtedness that will be converted into equity under the Plan, but the annual limitation would be zero and we will lose the use of the entire NOLs in the event we experience another ownership change within two years after the Plan Effective Date. We anticipate that we will experience an ownership change as a result of the Plan; accordingly, the ability to use pre-change tax attributes to offset our future taxable income or taxes owed pre-ownership may be significantly limited.

Consummation of the Plan may impair certain of the tax assets of our Australian operations.

Our Australian operations have had significant net operating losses for Australian income tax purposes (Australian NOLs) through the taxable year ending December 31, 2016. The use of Australian NOLs is subject to our Australian operations satisfying the Continuity of Ownership Test (COT) in the first instance, or if that test is failed, the Same Business Test (the SBT). If our Australian operations satisfy either the COT or the SBT, they can apply Australian NOLs against Australian taxable income.

Our Australian operations currently rely on concessional ownership tracing rules to support the position that the operations continue to satisfy the COT. However, continuing to satisfy the COT depends upon there being at least 50 stockholders at all times prior to, during and immediately after the consummation of the Plan, of which 20 stockholders or fewer are not able to control 75% of the rights to vote, entitlement to dividends or rights to distributions on winding up. It is possible that the consummation of the Plan may cause our Australian operations to fail the COT. Should that happen, our Australian operations are able to fall back on the SBT, which generally requires that from the time the losses were incurred until the income year in which the Australian NOLs are sought to be used, the operations carried on substantially the same business and that during the same period the group did not enter into any new transactions of a kind it had previously not entered into. In the event that our Australian operations cannot satisfy either the COT or the SBT, although the NOLs are not technically canceled, the Australian NOLs cannot be used.

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Risks Associated with Our Operations

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

We operate in a competitive and highly regulated industry that for years has experienced strong headwinds. Decreased prices in the first three quarters of 2016 have reduced our revenues. For example, our revenues decreased during the year ended December 31, 2016 compared to the same period in 2015 by \$893.9 million, primarily due to lower realized pricing and lower sales volumes driven by various demand and production factors. In the fourth quarter of 2016, the coal industry saw sharp upturns in seaborne metallurgical and thermal coal pricing primarily due to restrictive production policies in China. However, these recent industry events do not demonstrate that these prices will be sustainable in the future and the vast majority of third-party analysts project that prices are likely to decline. If coal prices decrease or return to depressed levels, our operating results and profitability and value of our coal reserves could be materially and adversely affected.

Coal prices are dependent upon factors beyond our control, including:

- the demand for electricity;
- the strength of the global economy;
- the relative price of natural gas and other energy sources used to generate electricity;
- the demand for electricity and capacity utilization of electricity generating units (whether coal or non-coal);
- the demand for steel, which may lead to price fluctuations in the monthly and quarterly repricing of our metallurgical coal contracts;
- the global supply and production costs of thermal and metallurgical coal;
- changes in the fuel consumption and dispatch 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.

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 we negotiate pricing for metallurgical coal contracts quarterly and seaborne thermal coal contracts annually, with a substantial portion sold on a shorter-term basis.

Thermal coal accounted for the majority of our coal sales during 2015 and 2016. The vast 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) utilization of all electricity generating units (whether using coal or not), including the relative cost of producing electricity from all fuels, including coal; (iv) increasingly stringent environmental and other governmental regulations; and (v) the coal inventories of utilities. Gas-fueled generation has displaced and is expected to continue 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 along with flat electricity demand 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 volume and price of coal that we mine and sell.

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% and 23% our coal sales revenue in 2015 and 2016, respectively. Deteriorating conditions in the steel industry, including the demand for steel and the continued financial condition of the industry, could 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.

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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. The balance between coal demand and supply within the coal industry, factoring in demand and supply of closely related and competing segments such as natural gas, both domestically and internationally, could materially reduce coal prices and therefore materially reduce our revenues and profitability. We compete with producers of other low cost fuels used for electricity generation, such as natural gas and renewables. 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. Prices for coal vary by mining region and country. As a result, we cannot predict the future strength of the coal industry 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, 2016, we derived 28% of our total revenues from our five largest customers, similar to the prior year. Those five customers were supplied primarily from 24 coal supply agreements (excluding trading transactions) expiring at various times from 2017 to 2026. On an ongoing basis, we discuss the extension of existing agreements or entering into new long-term agreements with various customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term 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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One of our five largest customers is served by a single Peabody mine, included in our Western U.S. Mining operations, that has no other customers. Given the mine's location, it is currently unable to economically market its coal to other utility customers. This mine has a contract to supply coal to the customer's coal-fueled power plant through December 2019. The customer is owned by several private companies and one governmental entity. The non-governmental owners of the customer recently completed an evaluation of the plant and determined to continue operating the plant through December 2019, subject to certain conditions. Those non-governmental owners of the plant then issued a statement that they do not currently intend to be the operators the plant beyond December 2019; however, the United States Bureau of Reclamation -- also an owner of the customer -- has stated that it is investigating ways to continue operating the plant. The Company is currently discussing with the customer options to improve the plant's economics. If the customer closes the plant, our Western U.S. Mining operations revenues, Adjusted EBITDA and cash flows would be materially reduced. We could also incur accelerated costs related to the mine's closure and may be required to record asset impairment charges.

Our trading and hedging activities no longer cover certain risks, and may expose us to earnings volatility and other risks, including increasing requirements to post collateral.

We historically entered into hedging arrangements designed primarily to manage market price volatility of foreign currency (primarily the Australian dollar), diesel fuel and coal. Currently, we primarily enter into hedging arrangements designed to manage coal industry price through our trading and marketing functions; however, we may in the future enter into hedging arrangements to manage the volatility of foreign currency, diesel fuel, or other matters. Some of these derivative trading instruments require us to post margin based on the value of those instruments and other credit factors. If the fair value of our hedge portfolio moves significantly, or if laws or regulations are passed requiring all hedge arrangements to be exchange-traded or exchange-cleared, we could be required to post additional margin. In addition, as a result of the Chapter 11 Cases and the volatility in global markets, we have increasingly been required to post margin under the requirements of these instruments. Further requirements to post margin could negatively impact our liquidity.

Through our trading and hedging activities, we are also exposed to 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.

We are currently subject to foreign currency exchange rate risk for non-U.S. dollar expenditures and balances and price risk on diesel fuel utilized in our mining operations. As noted above, we have historically used derivative financial instruments, including forward contracts, swaps and options, designated as cash flow hedges, to manage these risks. The Chapter 11 Cases constituted an event of default under these derivative financial instruments and the counterparties terminated the agreements shortly thereafter in accordance with contractual terms. As a result, we will be exposed to foreign currency exchange rate risk and the risk of fluctuations in the price of fuel.

Our operating results could be adversely affected by unfavorable economic and financial market conditions.

Our profits are affected, in large part, by industry conditions. Industry conditions are subject to a variety of factors beyond our control. 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. These conditions, among other factors, led to the filing of the Chapter 11 Cases. If any of these conditions return, if coal prices continue at or below levels experienced in 2015 and early 2016 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 will depend 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 if they fail to perform the terms of their contracts with us, our accounts receivable securitization program and our business could be adversely affected.

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

Our mining operations are subject to conditions that can impact the safety of our workforce, or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include:

- fires and explosions from methane gas or coal dust;
- accidental mine water discharges;
- weather, flooding and natural disasters; unexpected maintenance problems;
- unforeseen delays in implementation of mining technologies that are new to our operations;
- key equipment failures;
- variations in coal seam thickness;
- variations in coal quality;
- variations in the amount of rock and soil overlying the coal deposit;
- variations in rock and other natural materials; and
- variations in geologic conditions.

We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, such conditions could occur and have a substantial impact on our results of operations, financial condition or cash flows.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal could suffer.

Transportation costs represent a significant portion of the total cost of coal use and the cost of transportation is a critical factor in a customer's purchasing decision. Increases in transportation costs and the lack of sufficient rail and port capacity could lead to reduced coal sales.

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 \$1.6 billion, with terms ranging up to 26 years, that commit us to pay a minimum amount for rail and port commitments for the delivery of coal even if those commitments go unused. The take-or-pay provisions in these contracts sometimes allow us to apply amounts paid for subsequent deliveries, but these provisions have limitations and we may not be able to apply all such amounts so paid in all cases. Also, we may not be able to utilize the amount of capacity for which we have 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.

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An inability of trading, brokerage, mining or freight counterparties to fulfill the terms of their contracts with us could reduce our profitability.

In conducting our trading, brokerage and mining operations, we utilize third-party sources of coal production and transportation, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. We have completed several conversions to owner-operator status at certain of our Australian operations. Employee relations at mines that use contractors 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.

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. This may be mitigated by our application of fresh start reporting rules.

As described in Note 4. "Asset Impairment" to the accompanying consolidated financial statements, we recognized aggregate asset impairment costs of \$247.9 million, \$1,277.8 million and \$154.4 million in 2016, 2015 and 2014, 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, 2016, we had approximately 6,700 employees (excluding employees that were employed at operations classified as discontinued), which included approximately 5,100 hourly employees. Approximately 39% of our hourly employees were represented by organized labor unions and generated approximately 22% of 2016 coal production for the 12 months ended December 31, 2016. Relations with our employees and, where applicable, organized labor are important to our success. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs. Also, if we fail to maintain good relations with our union workforce, we could experience labor disputes, work stoppages or other disruptions in production that could negatively impact our profitability.

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We could be adversely affected if we fail to appropriately provide financial assurances for our obligations. U.S. federal and state laws and Australian laws require us to provide financial assurances related to requirements to reclaim lands used for mining, to pay federal and state workers' compensation, to provide financial assurances for 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, 2016, we had \$1,094.2 million of self-bonding in place for our U.S. coal mine reclamation obligations. As of December 31, 2016, we also had outstanding surety bonds with third parties, bank guarantees and letters of credit of \$921.3 million, of which \$607.5 million was for post-mining reclamation, \$61.8 million related to workers' compensation and other insurance obligations, \$94.0 million was for coal lease obligations and \$158.0 million was for other obligations, including road maintenance and performance guarantees. In addition, as of December 31, 2016, we had posted letters of credit and cash collateral in support of these financial instruments of \$429.5 million. During 2015 and 2016, we were required to increase our total posted letters of credit to the issuing parties of certain of our surety bonds and bank guarantees, whereas we had not previously been required to do so. Surety bond issuers may demand additional collateral, which may in turn affect our available liquidity. Our bonding obligations may increase due to a number of factors, and, upon our emergence from Chapter 11 or otherwise, we may not continue to qualify to self-bond or self-bonding programs may be terminated. Alternative forms of financial assurance such as surety bonds and letters of credit may not be available to us. Our failure to retain, or inability to obtain surety bonds, bank guarantees or letters of credit, or to provide a suitable alternative, could 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; and
- inability to provide or fund collateral for current and future third-party surety bond issuers.

Our failure to maintain adequate bonding would invalidate our mining permits and prevent mining operations from continuing, which would cast substantial doubt on our ability to continue as a going concern. Our mining operations are extensively regulated, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal. 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, sediment and groundwater;
- air quality standards;
- water pollution;
- protection of human health, plant-life and wildlife, including endangered or threatened species and habitats;
- 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.

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For additional information about the various regulations affecting us, see the sections entitled “Regulatory Matters —U.S.” and “Regulatory Matters — Australia”.

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.

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 permitting process, when we apply for permits and approvals, we are required to prepare and present to governmental authorities data pertaining to the potential impact or 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 (including modifications and renewals of certain 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 permitting requirements 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.

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

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

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

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Moreover, the amount of proven and probable coal reserves described in Part I, Item 2. "Properties" involves 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, 2016, we leased a total of 59,626 acres from the federal government subject to those limitations. Many of these leases are in place for the next 20 years. On January 15, 2016, the Interior Department announced that it will perform a review of the federal coal leasing program. At that time, the Interior Department ordered a pause on issuing new coal leases which the Interior Department stated would continue for three years while the review of the federal coal leasing program occurs. 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. 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 and federal and state coal leases 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.

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Our global operations increase our exposure to risks unique to international mining and trading operations. Our international platform increases our exposure to country risks, international regulatory requirements 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 business and political risks, including political instability, heightened levels of corruption or fraud in certain markets, 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 perform due diligence, screening, training and auditing of internal and external business agents, vendors, partners and customers 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.

We may undertake further repositioning plans that would require additional charges.

As a result of our continuing review of our business or changing demand, we may choose to further reduce our workforce in the future. These actions may result in further restructuring charges, 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.

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 \$812.1 million as of December 31, 2016, of which \$55.8 million was classified as a current liability. Certain of our U.S. subsidiaries also sponsor defined benefit pension plans. Net pension liabilities were \$186.3 million as of December 31, 2016, of which none was classified a current liability.

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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 Guaranty Corporation (PBGC) may terminate our plans under certain circumstances pursuant to ERISA, 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.

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 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.

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. 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 CCUS 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.

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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.

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Risks Related to Our Indebtedness and Expected Post-Emergence Capital Structure under the Plan

If the Plan becomes effective, our common stock will be extinguished, canceled and discharged on the Plan Effective Date.

If the Plan becomes effective, our common stock will be extinguished, canceled and discharged on the Plan Effective Date. Under the Plan, holders of our common stock are not entitled to receive, and will not receive or retain, any property or interest in property on account of such equity interests. In the event of cancellation of our common stock, amounts invested by the holders will not be recoverable and the common stock will have no value. Trading prices for Peabody Energy's equity or other securities prior to the Plan Effective Date may bear little or no relationship to the actual recovery, if any, by the holders thereof on the Plan Effective Date. Our common stock may continue to trade even though it will be extinguished, canceled and discharged on the Plan Effective Date if the Plan becomes effective. Accordingly, Peabody Energy urges caution with respect to existing and future investments in its equity or other securities.

Following our expected emergence from our Chapter 11 Cases, we will continue to face a number of risks that could materially and adversely affect our business.

Following our expected emergence from our Chapter 11 Cases, we will continue to face a number of risks, including certain risks that are beyond our control, such as deterioration or other changes in economic conditions, changes in the industry, changes in customer demand for, and acceptance of, our coal, and increasing expenses. As a result of these risks and others, there is no guarantee that the Plan will achieve our stated goals.

Furthermore, even though our overall indebtedness will be reduced through the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the Plan Effective Date. Adequate funds may not be available when needed or may not be available on favorable terms.

Following our expected emergence from our Chapter 11 Cases, there will not be an established market for shares of Reorganized PEC Common Stock or our Preferred Equity, which means there are uncertainties regarding the prices and terms on which holders could dispose of their shares, if at all.

No established market exists for the new common stock (Reorganized PEC Common Stock) or the preferred stock (Preferred Equity) to be issued pursuant to the Plan. We will use our reasonable best efforts to cause the Reorganized PEC Common Stock and Preferred Equity to be listed for trading on the New York Stock Exchange (NYSE) as soon as practicable following the Plan Effective Date. However, the Company cannot give assurances as to whether the NYSE will approve the Reorganized PEC Common Stock or Preferred Equity for listing or when any such listing will occur. There can be no assurance that the Reorganized PEC Common Stock or Preferred Equity will be listed on the NYSE or any other national exchange or interdealer quotation system or that we will continue to meet the requirements for listing once a listing has been approved. If the Reorganized PEC Common Stock or Preferred Equity is not listed on a national exchange or interdealer quotation system, we intend to cooperate with any registered broker-dealer who may seek to initiate price quotations for the Reorganized PEC Common Stock or Preferred Equity in the over-the-counter market. Again, however, no assurance can be given that such securities will be quoted on the over-the-counter market. We, therefore, cannot provide any assurance that the Reorganized PEC Common Stock or Preferred Equity will be publicly tradable at any time after the Plan Effective Date. If no public market for the Reorganized PEC Common Stock or Preferred Equity develops, holders of such securities may have difficulty selling or obtaining timely and accurate quotations with respect to such securities.

There cannot be any assurance as to the degree of price volatility in any market that develops for the Reorganized PEC Common Stock or Preferred Equity. Some holders who receive Reorganized PEC Common Stock or Preferred Equity pursuant to the Plan may not elect to hold equity on a long-term basis. Sales by future stockholders of a substantial number of shares after the Plan Effective Date could significantly reduce the market price of the Reorganized PEC Common Stock or Preferred Equity. Moreover, the perception that these stockholders might sell significant amounts of the Reorganized PEC Common Stock or Preferred Equity could depress the trading price of the shares for a considerable period. Under the terms of a registration rights agreement contemplated by the Plan, we will be required to file a shelf registration statement that will permit certain holders of Reorganized PEC Common Stock and/or Preferred Equity acquiring shares in connection with the Plan to sell their shares in the public markets. Sales of the Reorganized PEC Common Stock or Preferred Equity, and the possibility thereof, could make it more difficult for us

to sell equity, or equity-related securities, in the future at a time and price that we consider appropriate.

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Reorganized PEC Common Stock will be subject to dilution and may be subject to further dilution in the future. Reorganized PEC Common Stock to be issued on the Plan Effective Date is subject to dilution from the long-term incentive plan (LTIP) contemplated by the Plan, the Preferred Equity, payment-in-kind dividends to be paid to holders of Preferred Equity and certain warrants expected to be issued on the Plan Effective Date. In addition, in the future, we may issue equity securities in connection with future investments, acquisitions or capital raising transactions. Such issuances or grants could constitute a significant portion of the then-outstanding common stock, which may result in significant dilution in ownership of common stock, including shares of Reorganized PEC Common Stock issued pursuant to the Plan. In addition, holders of Reorganized PEC Common Stock will be subordinated to the Preferred Equity to the extent of the Preferred Equity's liquidation preference.

Following our expected emergence from our Chapter 11 Cases, the potential payment of dividends on our stock or repurchases of our stock will be dependent on a number of factors, and future payments and repurchases cannot be assured.

It is uncertain whether we will pay cash dividends or other distributions with respect to our post-emergence stock in the foreseeable future. Restrictive covenants in certain debt instruments to which we or our subsidiaries will, or may, be a party, may limit our ability to pay dividends or for us to receive dividends from our subsidiaries, any of which may negatively impact the trading price of the Reorganized PEC Common Stock and Preferred Equity. In addition, holders of our post-emergence stock will only be entitled to receive such cash dividends as our Board of Directors may declare out of funds legally available for such payments, and our Board of Directors may only authorize us to repurchase shares of our post-emergence stock with funds legally available for such repurchases. The payment of future cash dividends and future repurchases will depend upon our earnings, economic conditions, liquidity and capital requirements, and other factors, including our debt leverage. In addition, the terms of the Preferred Equity will limit our ability to pay cash dividends on or purchase shares of Reorganized PEC Common Stock without the consent of holders representing at least a majority of the outstanding shares of the Preferred Equity. Accordingly, we cannot make any assurance that future dividends will be paid or future repurchases will be made.

Following our emergence from our Chapter 11 Cases under the Plan, we expect to have substantial indebtedness, and our financial performance could be adversely affected by our substantial indebtedness.

Our financial performance could be affected by our substantial indebtedness. As of December 31, 2016, we had approximately \$7.8 billion of indebtedness outstanding on a consolidated basis. Upon emergence from our Chapter 11 Cases under the Plan, we expect to have \$1.95 billion of indebtedness outstanding, excluding capital leases, on a consolidated basis.

The degree to which we are leveraged could have important consequences, including, but not limited to:

- making it more difficult for us to pay interest and satisfy our debt obligations;
- increasing the cost of borrowing under our credit facilities;
- increasing our vulnerability to general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal and interest on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, business development or other general corporate requirements;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, business development or other general corporate requirements;
- making it more difficult to obtain surety bonds, letters of credit, bank guarantees or other financing, particularly during periods in which credit markets are weak;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry;
- causing a decline in our credit ratings; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

In addition, our future indebtedness under the Plan is expected to subject us to certain restrictive covenants. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have a material adverse effect on us and result in amounts outstanding thereunder to be immediately due and payable.

Any downgrade in our credit ratings could result in, among other matters, additional required financial assurances related to our reclamation obligations, a requirement to post additional collateral on derivative trading instruments that

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we may enter into, the loss of trading counterparties for corporate hedging and trading and brokerage activities or an increase in the cost of, or a limit on our access to, various forms of credit used in operating our business.

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If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Under the Plan, we expect our future indebtedness will restrict our ability to sell assets outside of the ordinary course of business and will restrict the use of the proceeds from any such sales. We may not be able to complete those sales or obtain the proceeds which we could realize from them, and these proceeds may not be adequate to meet any debt service obligations then due. In addition, the terms of our future indebtedness under the Plan provide that if we cannot meet our debt service obligations, the lenders could foreclose against the assets securing their borrowings and we could be forced into bankruptcy or liquidation.

Despite our and our subsidiaries' expected level of indebtedness following the Plan Effective Date, we may still be able to incur substantially more debt, including secured debt. This could further increase the risks associated with our substantial indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, including additional secured debt. Although covenants under the indenture governing the senior secured notes to be outstanding following the Plan Effective Date (New Senior Secured Notes) and the agreements governing our other post-emergence indebtedness (Exit Financings) will limit our ability to incur additional indebtedness, these restrictions are subject to a number of qualifications and exceptions and, under certain circumstances, debt incurred in compliance with these restrictions can be substantial. In addition, the indenture governing the New Senior Secured Notes and the agreements governing our other Exit Financings will not limit us from incurring obligations that do not constitute indebtedness as defined therein.

After the Plan Effective Date, we expect that approximately \$950.0 million will be outstanding under our new senior secured term loan facility (New Credit Facility) as of the Plan Effective Date. Additionally, prior to the final maturity date of our New Credit Facility, we may add one or more incremental term loan facilities or other first lien debt in an aggregate principal amount not to exceed (a) \$300 million plus (b) an additional amount subject to compliance with a specified first lien leverage ratio, subject to certain other conditions.

We may not be able to generate sufficient cash to service all of our post-emergence indebtedness or other obligations. Our ability to make scheduled payments on, or refinance our debt obligations, depends on our financial condition and operating performance, which are subject to prevailing economic, industry, and competitive conditions and to certain financial, business, legislative, regulatory, and other factors beyond our control. We may be unable to maintain a level of cash flow from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

The covenants in our indenture governing the New Senior Secured Notes and the agreements and instruments governing our other post-emergence indebtedness, including the other Exit Financings, impose restrictions that may limit our operating and financial flexibility.

The indenture governing the New Senior Secured Notes and the agreements and instruments governing our other post-emergence indebtedness, including the other Exit Financings, will 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, which could adversely affect our ability to operate our business, as well as significantly affect our liquidity, and therefore could adversely affect our results of operations.

These covenants restrict, among other things, our ability to:

- incur additional indebtedness;
- pay dividends on or make distributions in respect of stock or make certain other restricted payments or investments;
- enter into agreements that restrict distributions from certain subsidiaries;
- sell or otherwise dispose of assets;
- enter into transactions with affiliates;
- create or incur liens;
- merge, consolidate or sell all or substantially all of our assets; and

- place restrictions on the ability of subsidiaries to pay dividends or make other payments to us.

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Our ability to comply with these covenants may be affected by events beyond our control and we may need to refinance existing debt in the future. A breach of any of these covenants together with the expiration of any cure period, if applicable, could result in a default under the New Senior Secured Notes. If any such default occurs, subject to applicable grace periods, the holder of New Senior Secured Notes may elect to declare all outstanding New Senior Secured Notes, together with accrued interest and other amounts payable thereunder, to be immediately due and payable. If the obligations under the New Senior Secured Notes were to be accelerated, our financial resources may be insufficient to repay the notes and any other indebtedness becoming due in full.

In addition, if we breach the covenants in the indentures governing the New Senior Secured Notes and do not cure such breach within the applicable time periods specified therein, we would cause an event of default under the indenture governing the New Senior Secured Notes and a cross-default to certain of our other Exit Financings and the lenders or holders thereunder could accelerate their obligations. If our indebtedness is accelerated, we may not be able to repay our indebtedness 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 indebtedness 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 make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

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, 2016, we had gross deferred income tax assets and liabilities of \$4,978.0 million and \$1,114.4 million, respectively, as described further in Note 12. "Income Taxes" to the accompanying consolidated financial statements. At that date, we also had recorded a valuation allowance of \$3,881.2 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.

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, as in effect now, 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. The certificate of incorporation and by-laws that will govern us following the Plan Effective Date are expected to include similar provisions.

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.

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Item 2. Properties.

Coal Reserves

We controlled an estimated 5.6 billion tons of proven and probable coal reserves as of December 31, 2016. An estimated 4.9 billion tons of our attributable proven and probable coal reserves are in the U.S., with the remainder in Australia. Approximately 63% of our Australian proven and probable coal reserves, or 448 million tons, are metallurgical coal, comprised of approximately 183 million and 265 million tons of coking coal and LV PCI coals, respectively. The remainder of our Australian coal reserves consists of thermal coal. We own approximately 28% of these reserves and leased property comprises the remaining 72%. Approximately 65% of our reserves, or 3.6 billion tons, are compliance coal and 35% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emission allowance credits or blending higher sulfur coal with lower sulfur coal.

Below is a table summarizing the locations and proven and probable coal reserves of our major mining segments.

Mining Segment	Locations	Proven and Probable Reserves as of December 31, 2016 ⁽¹⁾		
		Owned Tons	Leased Tons	Total Tons
Powder River Basin Mining	Wyoming	—	2,713	2,713
Midwestern U.S. Mining	Illinois, Indiana and Kentucky	1,425	297	1,722
Western U.S. Mining	Arizona, New Mexico and Colorado	171	325	496
Total United States		1,596	3,335	4,931
Australian Metallurgical Mining	Queensland and New South Wales	—	418	418
Australian Thermal Mining	New South Wales	—	294	294
Total Australia		—	712	712
Total Proven and Probable Coal Reserves		1,596	4,047	5,643

⁽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.

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The preparation of our coal reserve estimates is completed in accordance with our prescribed internal control procedures, which include verification of input data into a coal reserve forecasting and economic evaluation software system, as well as multi-functional management review. Our reserve estimates are prepared by our staff of experienced geologists and engineers. Our corporate Geological Services group is responsible for tracking changes in reserve estimates, supervising our other geologists and coordinating periodic third-party reviews of our reserve estimates by qualified mining consultants.

Our coal reserve estimates are predicated on information obtained from an extensive historical database of 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 market 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, 2016 reflected a net reduction compared to the prior year of 693 million 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 66 million production tons.

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, 2016, we leased 6,785 acres of federal land in Colorado, 640 acres in New Mexico and 52,201 acres in Wyoming, for a total of 59,626 nationwide subject to those limitations.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 64,858 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.

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

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Mining and exploration in Australia is generally carried 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 5.6 billion tons, we believe that we have sufficient coal reserves to replace capacity from depleting mines for the foreseeable future and that our significant coal reserve holdings is one of our competitive strengths. We believe that the current level of production at our major mines is sustainable for the foreseeable future.

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The following charts provide a summary, by mining complex, of production (in descending order by mining segment) for the years ended December 31, 2016, 2015 and 2014, 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)

Segment/Mining Complex	Production			Type of Coal	Sulfur Content of Assigned Reserves as of December 31, 2016 (1)			As Received Btu per pound ⁽²⁾
	Year Ended December 31,				<1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	
	2016	2015	2014		Million Btu	Million Btu	Million Btu	
Powder River Basin Mining:								
North Antelope Rochelle	92.9	109.3	118.0	T	1,920	—	—	8,800
Caballo	11.2	11.4	8.0	T	476	6	6	8,400
Rawhide	8.1	15.2	15.4	T	248	56	1	8,300
Total	112.2	135.9	141.4		2,644	62	7	
Midwestern U.S. Mining:								
Bear Run	7.3	7.9	8.4	T	4	28	208	11,000
Wild Boar	2.6	2.7	3.5	T	—	—	35	11,100
Somerville Central	2.3	3.0	3.4	T	—	—	15	11,200
Francisco Underground	2.1	2.9	3.1	T	—	—	28	11,500
Gateway North	1.8	1.8	2.5	T	—	—	61	10,800
Wildcat Hills Underground	1.5	1.7	2.0	T	—	—	29	12,100
Cottage Grove	0.2	1.1	1.9	T	—	—	5	12,200
Viking - Corning Pit (Closed in 2014)	—	—	0.1	T	—	—	—	NA
Total	17.8	21.1	24.9		4	28	381	
Western U.S. Mining:								
Kayenta	5.4	6.8	8.1	T	139	61	3	10,600
El Segundo	4.9	7.5	8.4	T	14	34	34	9,000
Twentymile	2.0	3.5	6.7	T	38	—	—	11,200
Lee Ranch	—	—	—	T	14	66	9	9,400
Total	12.3	17.8	23.2		205	161	46	
Australian Metallurgical Mining:								
Millennium	3.5	4.4	3.9	M/P	4	—	—	12,600
Coppabella	2.4	2.8	3.2	P	31	—	—	12,600
Moorvale	1.9	2.2	2.4	P	9	—	—	12,300
Metropolitan ⁽³⁾	1.9	2.1	2.5	M	26	—	—	12,600
Burton	1.5	1.3	1.9	M/T	7	—	—	12,700
North Goonyella	1.3	2.6	2.9	M	87	—	—	12,700

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Middlemount ⁽⁴⁾	—	—	—	M/P	28	—	—	12,300
Total	12.5	15.4	16.8		192	—	—	
Australian Thermal Mining:								
Wilpinjong	14.0	12.0	14.4	T	149	—	—	10,000
Wambo ⁽⁵⁾	6.8	6.5	6.5	M/T	145	—	—	11,800
Total	20.8	18.5	20.9		294	—	—	
Total Assigned	175.6	208.7	227.2		3,339	251	434	

T: Thermal

M: Metallurgical

P: Pulverized Coal Injection Metallurgical

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AS OF DECEMBER 31, 2016

(Tons in Millions)	Segment/Mining Complex	Interest	Attributable Ownership				100% Project Basis					
			Proven and Probable Reserves	Owned	Leased	Surface	Underground	Proven and Probable Reserves	Owned	Leased	Surface	Underground
Powder River Basin												
Mining:												
	North Antelope Rochelle	100%	1,920	—	1,920	1,920	—	1,920	—	1,920	1,920	—
	Caballo	100%	488	—	488	488	—	488	—	488	488	—
	Rawhide	100%	305	—	305	305	—	305	—	305	305	—
	Total		2,713	—	2,713	2,713	—					
Midwestern U.S. Mining:												
	Bear Run	100%	240	104	136	240	—	240	104	136	240	—
	Wild Boar	100%	35	19	16	35	—	35	19	16	35	—
	Somerville Central	100%	15	14	1	15	—	15	14	1	15	—
	Francisco Underground	100%	28	5	23	—	28	28	5	23	—	28
	Gateway North	100%	61	59	2	—	61	61	59	2	—	61
	Wildcat Hills	100%	29	11	18	—	29	29	11	18	—	29
	Underground											
	Cottage Grove	100%	5	3	2	5	—	5	3	2	5	—
	Total		413	215	198	295	118					
Western U.S. Mining:												
	Kayenta	100%	203	—	203	203	—	203	—	203	203	—
	El Segundo	100%	82	68	14	82	—	82	68	14	82	—
	Twentymile	100%	38	10	28	—	38	38	10	28	—	38
	Lee Ranch	100%	89	87	2	89	—	89	87	2	89	—
	Total		412	165	247	374	38					
Australian Metallurgical												
Mining:												
	Millennium	100%	4	—	4	4	—	4	—	4	4	—
	Coppabella	73.3%	31	—	31	31	—	42	—	42	42	—
	Moorvale	73.3%	9	—	9	9	—	12	—	12	12	—
	Metropolitan ⁽³⁾	100%	26	—	26	—	26	26	—	26	—	26
	Burton	100%	7	—	7	7	—	7	—	7	7	—
	North Goonyella	100%	87	—	87	—	87	87	—	87	—	87
	Middlemount ⁽⁴⁾	50.0%	28	—	28	28	—	56	—	56	56	—
	Total		192	—	192	79	113					
Australian Thermal												
Mining:												
	Wilpinjong	100%	149	—	149	149	—	149	—	149	149	—
	Wambo ⁽⁵⁾	100%	145	—	145	34	111	145	—	145	34	111
	Total		294	—	294	183	111					

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Total Assigned 4,024 380 3,644 3,644 380

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES ⁽⁶⁾
AS OF DECEMBER 31, 2016
(Tons in Millions)

Coal Seam Location	Attributable Ownership					100% Project Basis				
	Total Tons Assigned		Proven and Probable Reserves	Proven	Probable	Total Tons Assigned		Proven and Probable Reserves	Proven	Probable
Powder River Basin Mining (Wyoming)	2,713	—	2,713	2,587	126	2,713	—	2,713	2,587	126
Midwestern U.S. Mining:										
Illinois	95	1,156	1,251	554	697	95	1,156	1,251	554	697
Indiana	318	29	347	289	58	318	29	347	289	58
Kentucky ⁽⁷⁾	—	124	124	54	70	—	124	124	54	70
Total	413	1,309	1,722	897	825					
Western U.S. Mining:										
Arizona	203	—	203	203	—	203	—	203	203	—
New Mexico	171	—	171	171	—	171	—	171	171	—
Colorado	38	84	122	79	43	38	84	122	79	43
Total	412	84	496	453	43					
Australian Metallurgical Mining:										
New South Wales	26	—	26	6	20	26	—	26	6	20
Queensland	166	226	392	223	169	208	289	497	277	220
Total	192	226	418	229	189					
Australian Thermal Mining (New South Wales)	294	—	294	237	57	294	—	294	237	57
Total Proven and Probable	4,024	1,619	5,643	4,403	1,240					

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ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2016
(Tons in Millions)

Coal Seam Location	Attributable Ownership				100% Project Basis			
	Reserve Control		Mining Method		Reserve Control		Mining Method	
	Owned	Leased	Surface	Underground	Owned	Leased	Surface	Underground
Powder River Basin Mining (Wyoming)	—	2,713	2,713	—	—	2,713	2,713	—
Midwestern U.S. Mining:								
Illinois	1,217	34	9	1,242	1,217	34	9	1,242
Indiana	165	182	301	46	165	182	301	46
Kentucky ⁽⁷⁾	43	81	—	124	43	81	—	124
Total	1,425	297	310	1,412				
Western U.S. Mining:								
Arizona	—	203	203	—	—	203	203	—
New Mexico	154	17	171	—	154	17	171	—
Colorado	17	105	—	122	17	105	—	122
Total	171	325	374	122				
Australia Metallurgical Mining:								
New South Wales	—	26	—	26	—	26	—	26
Queensland	—	392	179	213	—	497	249	248
Total	—	418	179	239				
Australian Thermal Mining (New South Wales)	—	294	182	112	—	294	182	112
Total Proven and Probable	1,596	4,047	3,758	1,885				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2016
(Tons in Millions)

Coal Seam Location	Type of Coal	Attributable Ownership Sulfur Content ⁽¹⁾			100% Project Basis Sulfur Content ⁽¹⁾			As Received Btu per Pound ⁽²⁾
		<1.2 lbs. Sulfur Dioxide	>1.2 to 2.5 lbs. Sulfur Dioxide	>2.5 lbs. Sulfur Dioxide	<1.2 lbs. Sulfur Dioxide	>1.2 to 2.5 lbs. Sulfur Dioxide	>2.5 lbs. Sulfur Dioxide	
		per Million Btu	per Million Btu	per Million Btu	per Million Btu	per Million Btu	per Million Btu	
Powder River Basin Mining (Wyoming)	T	2,644	62	7	2,644	62	7	8,700
Midwestern U.S. Mining:								
Illinois	T	—	—	1,251	—	—	1,251	10,800
Indiana	T	4	28	315	4	28	315	11,000
Kentucky ⁽⁷⁾	T	—	—	124	—	—	124	12,000
Total		4	28	1,690				
Western U.S. Mining:								
Arizona	T	139	61	3	139	61	3	10,600
New Mexico	T	28	100	43	28	100	43	9,200
Colorado	T	122	—	—	122	—	—	11,200
Total		289	161	46				
Australia Metallurgical Mining:								
New South Wales	M	26	—	—	26	—	—	12,600
Queensland	M/P/T	392	—	—	497	—	—	12,400
Total		418	—	—				
Australian Thermal Mining (New South Wales)	T/M	294	—	—	294	—	—	10,800
Total Proven and Probable		3,649	251	1,743				

T: Thermal

M: Metallurgical

P: Pulverized Coal Injection Metallurgical

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

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

(3) On November 3, 2016, Peabody Australia Mining Pty Ltd, one of the Company's Australian subsidiaries, entered into a definitive share sale and purchase agreement (SPA) for the sale of all of its equity interest in Metropolitan Collieries Pty Ltd to a subsidiary of South32 Limited (South32). The closing of the transaction is conditional upon receipt of approval from the Australian Competition and Consumer Commission (ACCC). On February 22, 2017, the ACCC issued a Statement of Issues (SOI) relating to the transaction, noting that the ACCC is continuing to review the transaction. On February 24, 2017, pursuant to its right under the SPA, South32 extended the CP End Date (as defined in the SPA) from March 3, 2017 to April 17, 2017. On March 21, 2017, the ACCC notified us that it has extended the date on which it intends to render its decision regarding the transaction to April 27, 2017, which extends beyond the CP End Date. As a result, we are assessing our options under the SPA.

(4) Represents our 50% interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. Because that entity is accounted for as an unconsolidated equity affiliate, 2016, 2015 and 2014 tons produced by Middlemount have been excluded from the "Summary of Coal Production and Sulfur Content of Assigned Reserves" table. Middlemount produced 4.5 million tons of coal in 2016 (on a 100% basis).

(5) Includes the Wambo Open-Cut Mine and the Wambo Underground Mine areas.

(6) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2016. Unassigned reserves represent coal at currently non-producing locations that would require new mine development, mining equipment or plant facilities before operations could begin on the property.

(7) All coal reserves in Kentucky are leased to third parties.

Item 3. Legal Proceedings.

See Note 26. "Commitments and Contingencies" and Note 27. "Matters Related to the Bankruptcy of Patriot Coal Corporation" to our consolidated financial statements for a description of our pending legal proceedings, which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures.

Our "Safety a Way of Life Management System" has been designed to set clear and consistent expectations for safety and health across our business. It aligns to the National Mining Association's CORESafety® framework and encompasses three fundamental areas: leadership and organization, safety and health risk management and assurance. We 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 continually monitor our safety performance and regulatory compliance. The information concerning mine safety violations or other regulatory matters required by SEC regulations is included in Exhibit 95 to this Annual Report on Form 10-K.

PART II

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

Our common stock was listed on the New York Stock Exchange, under the symbol "BTU," until the Petition Date, when it was suspended from trading on the New York Stock Exchange. Our common stock began trading on the OTC Pink Sheets marketplace under the symbol "BTUUQ" on April 14, 2016. Following the Petition Date, the New York Stock Exchange formally de-listed our common stock. As of March 15, 2017 there were 809 holders of record of our common stock.

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If the Plan becomes effective, our common stock will be extinguished, canceled and discharged on the Plan Effective Date. Under the Plan, holders of our common stock are not to be entitled to receive, and will not receive or retain, any property or interest in property on account of such equity interests. In the event of cancellation of our common stock, amounts invested by the holders will not be recoverable and the common stock will have no value. Trading prices for Peabody Energy's equity or other securities prior to the Plan Effective Date may bear little or no relationship to the actual recovery, if any, by the holders thereof on the Plan Effective Date. Our common stock may continue to trade even though it will be extinguished, canceled and discharged on the Plan Effective Date if the Plan becomes effective. Accordingly, Peabody Energy urges caution with respect to existing and future investments in its equity or other securities.

All share and per share data have been retroactively restated to reflect the September 30, 2015 1-for-15 reverse stock split.

The table below sets forth the range of quarterly high and low sales prices (including intraday prices) for our common stock as reported on the market on which it traded at the time and the amount of cash dividends paid per share of our common stock during the calendar quarters indicated.

	Share Price		Dividends
	High	Low	Paid
2016			
First Quarter	\$7.87	\$2.00	\$ —
Second Quarter	2.43	0.55	—
Third Quarter	2.05	1.22	—
Fourth Quarter	18.75	1.43	—
2015			
First Quarter	\$123.45	\$71.40	\$ 0.0375
Second Quarter	84.00	28.80	0.0375
Third Quarter	41.10	14.85	—
Fourth Quarter	28.00	7.06	—

Dividend Policy

In connection with our ongoing efforts to manage our cash and preserve liquidity, our Board of Directors suspended our quarterly dividend beginning in the third quarter of 2015. As a result of the Chapter 11 Cases we are currently prohibited from paying dividends. Following the Plan Effective Date, our future indebtedness incurred under the Plan will include provisions that limit our ability to pay dividends. See Part I, Item 1A. "Risk Factors — Following our expected emergence from the Chapter 11 Cases, the potential payment of dividends on our stock and repurchases of our stock will be dependent on a number of factors, and future payments and repurchases cannot be assured."

Share Repurchases

On October 24, 2008, we announced that our Board of Directors approved an amendment to the then existing share repurchase program to authorize repurchases of up to \$1.0 billion of the then outstanding shares of our common stock (Repurchase Program). The Repurchase Program does not have an expiration date and may be discontinued at any time. From October 2008 through December 2012, we repurchased a total of 0.5 million shares under the Repurchase Program at a cost of \$299.6 million, leaving \$700.4 million available for share repurchases under the Repurchase Program. No share repurchases were made under the Repurchase Program during the years ended December 31, 2016, 2015 or 2014. As a result of the Chapter 11 Cases we are currently prohibited from repurchasing shares. Following the Plan Effective Date, our future indebtedness incurred under the Plan will include provisions that limit our ability to repurchase shares. See Part I, Item 1A. "Risk Factors — Following our expected emergence from the Chapter 11 Cases, the potential payment of dividends on our stock and repurchases of our stock will be dependent on a number of factors, and future payments and repurchases cannot be assured."

Share Relinquishments

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

the respective relinquishments.

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Purchases of Equity Securities

The following table summarizes all share purchases for the three months ended December 31, 2016:

Period	Total Number of Shares Purchased ⁽¹⁾	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Dollar Value that May Yet Be Used to Repurchase Shares Under the Publicly Announced Program (In millions)
October 1 through October 31, 2016	321	\$ 1.55	—	\$ 700.4
November 1 through November 30, 2016	272	14.10	—	700.4
December 1 through December 31, 2016	—	—	—	700.4
Total	593	\$ 7.31	—	

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

Item 6. Selected Financial Data.

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

The table that follows and the discussion of our results of operations in 2016, 2015 and 2014 in Part II, Item 7.

“Management’s Discussion and Analysis of Financial Condition and Results of Operations” includes references to and analysis of Adjusted EBITDA which is a financial measure not recognized in accordance with U.S. generally accepted accounting principles (U.S. GAAP). These financial measures are not intended to serve as alternatives to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies.

Adjusted EBITDA is used by management as the primary metric to measure our segments’ operating performance. We also believe non-U.S. GAAP performance measures are used by investors to measure our operating performance and lenders to measure our ability to incur and service debt. Adjusted EBITDA is defined as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expense, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing the segments’ operating performance, as displayed in the reconciliation. A reconciliation of income (loss) from continuing operations, net of income taxes to Adjusted EBITDA is included on page 52 of this report. Adjusted EBITDA is not intended to serve as an alternative to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies. The selected financial data for all periods presented reflect the classification as discontinued operations of certain operations previously divested (by sale or otherwise).

We have derived the selected historical financial data as of and for the years ended December 31, 2016, 2015, 2014, 2013 and 2012 from our audited financial statements, adjusted retrospectively for items subsequently classified as discontinued operations and the implementation of certain accounting literature. Also, all share and per share data have been retroactively restated to reflect the September 30, 2015 1-for-15 reverse stock split. The following table should be read in conjunction with the accompanying financial statements, including the related notes to those financial statements, and Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except per share data)				
Results of Operations Data					
Total revenues	\$4,715.3	\$5,609.2	\$6,792.2	\$7,013.7	\$8,077.5
Costs and expenses	4,992.2	7,074.0	6,927.3	7,338.5	7,905.0
Operating (loss) profit	(276.9)	(1,464.8)	(135.1)	(324.8)	172.5
Interest expense, net	322.4	525.5	412.8	409.5	381.1
Reorganization items, net	159.0	—	—	—	—
Loss from continuing operations before income taxes	(758.3)	(1,990.3)	(547.9)	(734.3)	(208.6)
Income tax (benefit) provision	(84.0)	(176.4)	201.2	(448.3)	262.3
Loss from continuing operations, net of income taxes	(674.3)	(1,813.9)	(749.1)	(286.0)	(470.9)
Loss from discontinued operations, net of income taxes	(57.6)	(175.0)	(28.2)	(226.6)	(104.2)
Net loss	(731.9)	(1,988.9)	(777.3)	(512.6)	(575.1)
Less: Net income attributable to noncontrolling interests	7.9	7.1	9.7	12.3	10.6
Net loss attributable to common stockholders	\$(739.8)	\$(1,996.0)	\$(787.0)	\$(524.9)	\$(585.7)
Basic and diluted EPS - Loss from continuing operations					
Weighted average shares used in calculating basic and diluted EPS	18.3	18.1	17.9	17.8	17.9
Dividends declared per share	\$—	\$0.075	\$5.100	\$5.100	\$5.100
Other Data					
Tons produced	175.6	208.7	227.2	218.4	225.4
Tons sold	186.8	228.8	249.8	251.7	248.5
Net cash provided by (used in) continuing operations:					
Operating activities	\$(22.9)	\$18.9	\$441.0	\$780.1	\$1,599.8
Investing activities	(244.1)	(290.0)	(314.5)	(514.2)	(1,070.1)
Financing activities	907.9	267.7	(168.1)	(321.5)	(663.3)
Adjusted EBITDA	492.2	434.6	814.0	1,047.2	1,836.5
Balance Sheet Data (at period end)					
Total assets	\$11,777.7	\$10,946.9	\$13,126.4	\$14,069.5	\$15,721.7
Total long-term debt (including capital leases)	7,791.4	6,241.2	5,922.1	5,938.5	6,156.6
Total stockholders' equity	337.8	918.5	2,726.5	3,947.9	4,938.8

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Adjusted EBITDA is calculated as follows:

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(Dollars in millions)				
Loss from continuing operations, net of income taxes	\$(674.3)	\$(1,813.9)	\$(749.1)	\$(286.0)	\$(470.9)
Depreciation, depletion and amortization	465.4	572.2	655.7	740.3	663.4
Asset retirement obligation expenses	41.8	45.5	81.0	66.5	67.0
Asset impairment and mine closure costs	247.9	1,277.8	154.4	528.3	929.0
Selling and administrative expenses related to debt restructuring	21.5	—	—	—	—
Settlement charges related to the Patriot bankruptcy reorganization	—	—	—	30.6	—
Change in deferred tax asset valuation allowance related to equity affiliates	(7.5)	(1.0)	52.3	—	—
Amortization of basis difference related to equity affiliates	—	4.9	5.7	6.3	4.6
Interest expense, net	322.4	525.5	412.8	409.5	381.1
Reorganization items, net	159.0	—	—	—	—
Income tax (benefit) provision	(84.0)	(176.4)	201.2	(448.3)	262.3
Adjusted EBITDA	\$492.2	\$434.6	\$814.0	\$1,047.2	\$1,836.5

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

Overview

In 2016, we produced and sold 175.6 million and 186.8 million tons of coal, respectively, from continuing operations. During that period, 76% of our total sales (by volume) were to U.S. electricity generators, 21% were to customers outside the U.S. and 3% were to the U.S. industrial sector, with approximately 86% of our worldwide sales (by volume) delivered under long-term contracts.

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 sulfur content and Btu and lower customer transportation costs (due to shorter shipping distances). Our Western U.S. Mining operations reflect the aggregation of the New Mexico, Arizona and Colorado mining operations. The mines in that segment are characterized by a mix of surface and underground mining extraction processes, coal with a mid-range sulfur content and Btu. 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 U.S. Mining operations mine both bituminous and sub-bituminous coal deposits.

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The business of our Australian operating platform is primarily export focused with customers spread across several countries, while a portion of our metallurgical and 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 coking 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, we may market some of our metallurgical coal products as a thermal coal product from time to time depending on market conditions.

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. Our Trading and Brokerage segment also provides transportation-related services, which involves both financial derivative contracts and physical contracts. Collectively, coal and freight-related hedging activities include both economic hedging and, from time to time, cash flow hedging in support of our coal trading strategy.

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.

Filing Under Chapter 11 of the United States Bankruptcy Code

On April 13, 2016, Peabody and a majority of its wholly owned domestic subsidiaries as well as one international subsidiary in Gibraltar (the Filing Subsidiaries, and together with Peabody, the Debtors) filed voluntary petitions for reorganization (the Bankruptcy Petitions) under Chapter 11 of Title 11 of the U.S. Code (the Bankruptcy Code) in the United States Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). The Company's Australian operations and other international subsidiaries are not included in the filings. The Debtors continue to operate their business as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. In general, as debtors-in-possession, the Debtors are authorized under Chapter 11 to continue to operate as an ongoing business, but may not engage in transactions outside the ordinary course of business without the prior approval of the Bankruptcy Court.

The filings of the Bankruptcy Petitions constituted an event of default under our prepetition credit agreement as well as the indentures governing certain of our debt instruments, as further described in Note 14. "Current and Long-term Debt" to the accompanying consolidated financial statements, and all unpaid principal and accrued and unpaid interest due thereunder became immediately due and payable. Any efforts to enforce such payment obligations are automatically stayed as a result of the Bankruptcy Petitions and the creditors' rights of enforcement are subject to the applicable provisions of the Bankruptcy Code.

In August 2016, we outlined a business plan intended to form the basis for our plan of reorganization, as further described below. As a result of our reorganization, we expect to emerge from the Chapter 11 Cases with the competitive cost structure necessary to improve our financial position and provide long-term stability for our stakeholders in the face of potentially volatile market conditions. Important aspects of our emergence business strategy include (i) a continued focus on safe, cost-disciplined mining operations and reclamation activities, (ii) maximization of the most profitable elements of our asset base and potential divestiture of non-strategic assets, (iii)

investment return-driven capital discipline, and (iv) a reduction of overall debt and fixed charges.

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In order to successfully emerge from our Chapter 11 Cases, the Debtors must propose and obtain confirmation from the Bankruptcy Court of a plan of reorganization that satisfies the requirements of the Bankruptcy Code. On January 27, 2017, the Debtors filed with the Bankruptcy Court the Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, the Plan) and the Second Amended Disclosure Statement with Respect to Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (previous versions of the Plan and Disclosure Statement were filed with the Bankruptcy Court on December 22, 2016, January 25, 2017 and January 27, 2017). Subsequently, the Debtors solicited votes on the Plan. On March 15, 2017, the Debtors filed a revised version of the Plan. On March 16, 2017, the Bankruptcy Court held a hearing to determine whether the Plan should be confirmed. On March 17, 2017, the Bankruptcy Court entered an order confirming the Plan. The Plan provides for, among other things, (1) classification and treatment of various claims and equity interests, (2) a reduction of our debt upon emergence, and (3) recapitalization through a rights offering and private placement for equity securities of the reorganized company. For additional details regarding the Bankruptcy Petitions and the Debtors' plan of reorganization, refer to Note 1. "Summary of Significant Accounting Policies" to the accompanying consolidated financial statements.

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

Results of Operations

Reverse Stock Split

Pursuant to the authorization provided at a special meeting of our stockholders held on September 16, 2015, we completed a 1-for-15 reverse stock split of the shares of our common stock on September 30, 2015 (the Reverse Stock Split). As a result of the Reverse Stock Split, every 15 shares of issued and outstanding common stock were combined into one issued and outstanding share of Common Stock, without any change in the par value per share. Our common stock began trading on a reverse stock split-adjusted basis on October 1, 2015. All share and per share data included in this report has been retroactively restated to reflect the Reverse Stock Split.

Non-U.S. GAAP Financial Measures

The following discussion of our results of operations includes references to and analysis of Adjusted EBITDA, which is a financial measure not recognized in accordance with U.S. GAAP. Adjusted EBITDA is used by management as the primary metric to measure our segments' operating performance. We believe non-U.S. GAAP performance measures are used by investors to measure our operating performance and lenders to measure our ability to incur and service debt.

Adjusted EBITDA is defined as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expense, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing our segments' operating performance, as displayed in the reconciliation. Adjusted EBITDA is not intended to serve as an alternative to U.S. GAAP measures of performance and may not be comparable to similarly-titled measures presented by other companies.

A reconciliation of Adjusted EBITDA to its most comparable measure under U.S. GAAP is included in Note 29. "Segment and Geographic Information" of the consolidated financial statements, which information is incorporated herein by reference.

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Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Summary

Demand for seaborne metallurgical coal for the year ended December 31, 2016 increased compared to 2015, driven by stronger demand in China following policy measures reducing domestic coal production and on stronger China steel production. Worldwide steel production increased by 0.8% in 2016, according to data recently published by the World Steel Association (WSA), with China's crude steel production up 1.2% compared to 2015. International seaborne metallurgical and thermal coal prices increased sharply in the second half of 2016, reaching multi-year highs driven by tightening coal supply and improved coal import demand from China. Benchmark pricing for seaborne premium high quality hard coking coal (HQHCC) and premium LV PCI products for 2016 and 2015 were as follows (on a per tonne basis):

Contract Commencement Month:	HQHCC			Price	LV PCI			Price
	2016	2015	%	(Decrease) Increase	2016	2015	(Decrease) Increase	
January	\$81	\$117	(31))%	\$69	\$99	(30))%
April	\$84	\$110	(24))%	\$73	\$93	(22))%
July	\$93	\$93	—	%	\$75	\$73	3	%
October	\$200	\$89	125	%	\$133	\$71	87	%

During the year ended December 31, 2016, HQHCC and Newcastle index thermal coal realized the following spot pricing:

	High	Low	Average	December 31, 2016
High quality hard coking coal	\$310	\$73	\$143	\$230
Newcastle index thermal coal	\$115	\$49	\$66	\$88

In the U.S., electricity generation from coal decreased 9% during the year ended December 31, 2016 compared to 2015, according to the U.S. Energy Information Administration (EIA). U.S. electricity generation from coal was unfavorably affected during that period by coal-to-gas switching due to comparatively low natural gas prices during the first half of 2016, high coal stockpiles and lower heating-degree days due to mild weather. During the first half of 2016 coal and natural gas accounted for 28% and 33%, respectively, of the electricity generation mix. During the second half of 2016, coal increased its relative share of the generation mix, as coal and natural gas accounted for approximately 32% and 34%, respectively, of electricity generation.

Our revenues decreased during the year ended December 31, 2016 compared to the prior year (\$893.9 million) primarily due to lower realized pricing in the U.S. and internationally and lower sales volumes driven by the demand and production factors mentioned above.

To mitigate the impact of lower coal pricing, we have continued to drive operational efficiencies, optimize production across our mining platform and control expenses at all operational and administrative levels of the organization, which has contributed to year-over-year decreases in our operating costs and expenses (\$900.1 million) and selling and administrative expenses (\$23.0 million). Also included in operating results for the year ended December 31, 2016 were aggregate restructuring charges of \$15.5 million, recognized in connection with certain actions initiated to reduce headcount and costs across our operating segments and administrative functions, which are expected to better align our workforce with our near-term outlook and improve our cost position moving forward.

Net loss attributable to common stockholders was \$739.8 million for the year ended December 31, 2016, a decrease of \$1,256.2 million compared to the net loss attributable to common stockholders of \$1,996.0 million in the prior year. Overall, Adjusted EBITDA of \$492.2 million for the year ended December 31, 2016 reflected a year-over-year increase of \$57.6 million. In addition to higher Adjusted EBITDA, the results were favorably impacted by lower asset impairment charges and decreased interest expense. These factors were partially offset by reorganization items recorded in connection with our Chapter 11 Cases.

As of December 31, 2016, our available liquidity was approximately \$0.9 billion consisting of cash and cash equivalents. Refer to the "Liquidity and Capital Resources" section contained within this Item 7 for further discussion

of factors affecting our available liquidity.

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Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2016 and 2015:

	Year Ended		(Decrease)	
	December 31		Increase	
	2016	2015	Tons	%
	to Tons Sold			
	(Tons in millions)			
Australian Metallurgical Mining	13.4	15.7	(2.3)	(14.6)%
Australian Thermal Mining	21.3	20.1	1.2	6.0 %
Powder River Basin Mining	113.1	138.8	(25.7)	(18.5)%
Western U.S. Mining	13.7	17.9	(4.2)	(23.5)%
Midwestern U.S. Mining	18.3	21.2	(2.9)	(13.7)%
Total tons sold from mining segments	179.8	213.7	(33.9)	(15.9)%
Trading and Brokerage	7.0	15.1	(8.1)	(53.6)%
Total tons sold	186.8	228.8	(42.0)	(18.4)%

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Supplemental Financial Data

The following table presents supplemental financial data by operating segment for the years ended December 31, 2016 and 2015:

	Year Ended		Increase	
	December 31,		(Decrease)	
	2016	2015	\$	%
Revenues per Ton - Mining Operations				
Australian Metallurgical	\$81.41	\$75.04	\$6.37	8 %
Australian Thermal	38.79	41.00	(2.21)	(5)%
Powder River Basin	13.02	13.45	(0.43)	(3)%
Western U.S.	38.30	38.09	0.21	1 %
Midwestern U.S.	43.39	46.18	(2.79)	(6)%
Operating Costs per Ton - Mining Operations ⁽¹⁾				
Australian Metallurgical	\$82.63	\$76.20	\$6.43	8 %
Australian Thermal	28.56	31.36	(2.80)	(9)%
Powder River Basin	9.66	9.97	(0.31)	(3)%
Western U.S.	30.90	27.78	3.12	11 %
Midwestern U.S.	31.49	33.49	(2.00)	(6)%
Gross Margin per Ton - Mining Operations ⁽¹⁾				
Australian Metallurgical	\$(1.22)	\$(1.16)	\$(0.06)	(5)%
Australian Thermal	10.23	9.64	0.59	6 %
Powder River Basin	3.36	3.48	(0.12)	(3)%
Western U.S.	7.40	10.31	(2.91)	(28)%
Midwestern U.S.	11.90	12.69	(0.79)	(6)%

Includes revenue-based production taxes and royalties; excludes depreciation, depletion and amortization; asset retirement obligation expenses; selling and administrative expenses; restructuring and pension settlement charges; asset impairment; and certain other costs related to post-mining activities. Gross margin per ton is approximately equivalent to segment Adjusted EBITDA divided by segment tons sold.

Revenues

The following table presents revenues by reporting segment for the years ended December 31, 2016 and 2015:

	Year Ended		(Decrease) Increase	
	December 31,		to Revenues	
	2016	2015	\$	%
(Dollars in millions)				
Australian Metallurgical Mining	\$1,090.4	\$1,181.9	\$(91.5)	(7.7)%
Australian Thermal Mining	824.9	823.5	1.4	0.2 %
Powder River Basin Mining	1,473.3	1,865.9	(392.6)	(21.0)%
Western U.S. Mining	526.0	682.3	(156.3)	(22.9)%
Midwestern U.S. Mining	792.5	981.2	(188.7)	(19.2)%
Trading and Brokerage	(10.9)	42.8	(53.7)	(125.5)%
Corporate and Other	19.1	31.6	(12.5)	(39.6)%
Total revenues	\$4,715.3	\$5,609.2	\$(893.9)	(15.9)%

Australia Metallurgical Mining. The decrease in our Australian Metallurgical Mining segment revenues for the year ended December 31, 2016 compared to the prior year was driven by unfavorable volume and mix variances (\$186.9 million), partially offset by higher realized coal prices (\$95.4 million). The volume decrease reflected lower sales volumes from Queensland mines due to weather impacts and lower production at our North Goonyella Mine resulting from a longwall move and a significant geological event which resulted in the cessation of the current longwall top coal caving system.

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Australia Thermal Mining. The slight increase in our Australian Thermal Mining segment revenues for the year ended December 31, 2016 compared to the prior year was primarily driven by higher volumes (\$47.6 million) offset by lower realized coal prices (\$46.2 million). The increase in tons sold was primarily driven by increased production at our Wilpinjong Mine as the result of receiving temporary approval during 2016 to ship tons in excess of its government mandated limit.

Powder River Basin Mining. The decrease in our Powder River Basin Mining segment revenues for the year ended December 31, 2016 compared to the prior year was largely driven by lower volume (\$335.7 million) and lower realized coal prices (\$56.9 million). The decline in volume across all mines in the segment reflected the impacts on customer demand of lower natural gas prices during the first half of 2016 and mild winter weather.

Western U.S. Mining. The decrease in our Western U.S. Mining segment revenues for the year ended December 31, 2016 compared to the prior year was primarily driven by an unfavorable volume and mix variance (\$146.4 million). The volume decrease reflected lower sales volumes at our Twentymile Mine due to lower production resulting from longwall moves (including an extended move to a new seam) and geological issues. The volume decrease was also driven by the litigation with Arizona Public Service Company and PacifiCorp that is further described in Note 26. "Commitments and Contingencies" of our consolidated financial statements.

Midwestern U.S. Mining. Revenues from our Midwestern U.S. Mining segment decreased during the year ended December 31, 2016 compared to the prior year due to lower volume (\$146.7 million) driven by the impacts on customer demand of lower natural gas prices. Revenues for the segment were also impacted by lower realized coal prices (\$42.0 million) that resulted from the repricing of certain long-term supply contracts.

Trading and Brokerage. The decline in Trading and Brokerage segment revenues for the year ended December 31, 2016 compared to the prior year reflected lower physical volumes shipped due to the impact of depressed coal pricing and unfavorable mark-to-market earnings from financial contract trading activities. We expect a significant portion of the unfavorable mark-to-market earnings to be offset in future periods upon the delivery of physical shipments which economically hedge the financial positions that related to the losses.

Loss From Continuing Operations Before Income Taxes

The following table presents loss from continuing operations before income taxes for the years ended December 31, 2016 and 2015:

	Year Ended		Increase (Decrease)	
	December 31,		to Income	
	2016	2015	\$	%
	(Dollars in millions)			
Loss from continuing operations before income taxes	\$ (758.3)	\$ (1,990.3)	\$ 1,232.0	61.9 %
Depreciation, depletion and amortization	(465.4)	(572.2)	106.8	18.7 %
Asset retirement obligation expenses	(41.8)	(45.5)	3.7	8.1 %
Selling and administrative expenses related to debt restructuring	(21.5)	—	(21.5)	n.m.
Asset impairment	(247.9)	(1,277.8)	1,029.9	80.6 %
Change in deferred tax asset valuation allowance related to equity affiliates	7.5	1.0	6.5	650.0 %
Amortization of basis difference related to equity affiliates	—	(4.9)	4.9	100.0 %
Interest expense	(298.6)	(465.4)	166.8	35.8 %
Loss on early debt extinguishment	(29.5)	(67.8)	38.3	56.5 %
Interest income	5.7	7.7	(2.0)	(26.0)%
Reorganization items, net	(159.0)	—	(159.0)	n.m.
Adjusted EBITDA	\$ 492.2	\$ 434.6	\$ 57.6	13.3 %

Results from continuing operations before income taxes for the year ended December 31, 2016 increased compared to the prior year primarily due to asset impairment charges recorded during the year ended December 31, 2015, improved Adjusted EBITDA, decreased interest expense and decreased depreciation, depletion and amortization expenses. Those factors were partially offset by reorganization items, net recorded during the year ended December 31, 2016.

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Adjusted EBITDA

The following table presents Adjusted EBITDA for each of our reporting segments for the years ended December 31, 2016 and 2015:

	Year Ended		Increase		
	December 31,		(Decrease) to		
	2016	2015	Adjusted		
			EBITDA		
			\$	%	
	(Dollars in millions)				
Australian Metallurgical Mining	\$(16.3)	\$(18.2)	\$1.9	10.4	%
Australian Thermal Mining	217.6	193.6	24.0	12.4	%
Powder River Basin Mining	379.9	482.9	(103.0)	(21.3)	%
Western U.S. Mining	101.6	184.6	(83.0)	(45.0)	%
Midwestern U.S. Mining	217.3	269.7	(52.4)	(19.4)	%
Trading and Brokerage	(72.2)	27.0	(99.2)	(367.4)	%
Corporate and Other	(335.7)	(705.0)	369.3	52.4	%
Adjusted EBITDA	\$492.2	\$434.6	\$57.6	13.3	%

Australian Metallurgical Mining. The improvement in Australian Metallurgical Mining segment Adjusted EBITDA during the year ended December 31, 2016 compared to the prior year reflected higher coal pricing (driven by fourth quarter price settlements), net of sales-related costs (\$88.9 million), offset by lower volume across the segment caused by the impact of longwall moves and geological issues at our North Goonyella Mine and the impact of wet weather at certain mines (\$79.7 million).

Australian Thermal Mining. The increase in Australian Thermal Mining segment Adjusted EBITDA during the year ended December 31, 2016 compared to the prior year reflected production efficiencies attributable to mine sequencing and lower port costs (\$41.7 million), an increase in volume (\$25.6 million), partially offset by lower coal pricing, net of sales-related costs (\$42.6 million).

Powder River Basin Mining. The decrease in Powder River Basin Mining segment Adjusted EBITDA during the year ended December 31, 2016 compared to the prior year was due to lower volume driven by lower natural gas prices, particularly in the first half of 2016 (\$87.4 million), lower coal pricing, net of sales-related costs (\$38.5 million) and the impact of mine sequencing, primarily at our North Antelope Rochelle Mine (\$21.6 million). These factors were partially offset by reductions in materials, services and repairs resulting from our ongoing cost containment initiatives (\$32.4 million) and lower diesel fuel and explosives pricing (\$11.1 million).

Western U.S. Mining. The decrease in Western U.S. Mining segment Adjusted EBITDA during the year ended December 31, 2016 compared to the prior year was driven by longwall move costs at our Twentymile Mine (\$38.5 million), a decline in volume driven by the contract litigation with Arizona Public Service Company and PacifiCorp that is further described in Note 26. "Commitments and Contingencies" of our consolidated financial statements (\$33.0 million) and the unfavorable impact of mine sequencing, primarily at our El Segundo Mine (\$12.2 million).

Midwestern U.S. Mining. The decrease in Midwestern U.S. Mining segment Adjusted EBITDA for the year ended December 31, 2016 compared to the prior year was due to lower volume driven by lower natural gas prices, particularly in the first half of 2016 (\$50.1 million) and lower coal pricing, net of sales-related costs (\$38.6 million), partially offset by favorable materials, services and repairs costs (\$15.2 million) and reductions in labor and overhead charges (\$11.4 million) resulting from our ongoing cost containment initiatives and favorable pricing and usage of fuel and explosives (\$9.5 million).

Trading and Brokerage. The decrease in Trading and Brokerage segment Adjusted EBITDA during the year ended December 31, 2016 compared to the prior year reflected the impact of decreased revenues described above and the impact of damages awarded in 2015 relating to the Eagle Mining, LLC (Eagle) arbitration and the settlement of the matter. Refer to Note 26. "Commitments and Contingencies" to the accompanying consolidated financial statements for additional information related to the Eagle matter.

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Corporate and Other Adjusted EBITDA. The following table presents a summary of the components of Corporate and Other Adjusted EBITDA for the years ended December 31, 2016 and 2015:

	Year Ended		(Decrease)	
	December 31,		Increase	
	2016	2015	\$	%
	(Dollars in millions)			
Resource management activities ⁽¹⁾	\$ 19.0	\$ 32.2	\$ (13.2)	(41.0)%
Selling and administrative expenses (excluding debt restructuring)	(131.9)	(176.4)	44.5	25.2 %
Restructuring charges	(15.5)	(23.5)	8.0	34.0 %
Corporate hedging	(241.0)	(436.8)	195.8	44.8 %
UMWA VEBA Settlement	68.1	—	68.1	n.m.
Other items, net ⁽²⁾	(34.4)	(100.5)	66.1	65.8 %
Corporate and Other Adjusted EBITDA	\$(335.7)	\$(705.0)	\$369.3	52.4 %

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

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

The increase associated with corporate hedging results, which includes foreign currency and commodity hedging, was due to lower hedge realizations. During the year ended December 31, 2016, a gain of \$68.1 million was recognized for the voluntary employee beneficiary association (VEBA) settlement with the United Mine Workers of America (UMWA) as further described in Note 27. "Matters Related to the Bankruptcy of Patriot Coal Corporation" of our consolidated financial statements. The significant reduction in selling and administrative expenses during the year ended December 31, 2016 compared to the prior year largely reflected the impact of our ongoing cost containment initiatives, including past restructuring activities. The increase associated with "Other items, net" is primarily attributable to lower charges on certain transportation-related contracts as compared to prior year and improved Middlemount results driven by favorable pricing in the fourth quarter of 2016. Restructuring charges decreased during the year ended December 31, 2016 compared to the prior year due to the larger staffing reductions at corporate and regional offices during the first half of 2015. Resource management results decreased during the year ended December 31, 2016 compared to the prior year due to increased gains from the disposal of non-core assets, primarily from surplus lands in the Midwestern U.S. during 2015.

Depreciation, Depletion and Amortization. The following table presents a summary of depreciation, depletion and amortization expense by segment for the years ended December 31, 2016 and 2015:

	Year Ended		Increase	
	December 31,		to Income	
	2016	2015	\$	%
	(Dollars in millions)			
Australian Metallurgical Mining	\$(118.7)	\$(178.9)	\$60.2	33.7%
Australian Thermal Mining	(102.5)	(108.0)	5.5	5.1 %
Powder River Basin Mining	(123.4)	(138.5)	15.1	10.9%
Western U.S. Mining	(45.2)	(55.3)	10.1	18.3%
Midwestern U.S. Mining	(56.2)	(69.0)	12.8	18.6%
Trading and Brokerage	(0.2)	(0.6)	0.4	66.7%
Corporate and Other	(19.2)	(21.9)	2.7	12.3%
Total	\$(465.4)	\$(572.2)	\$106.8	18.7%

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Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments for the years ended December 31, 2016 and 2015:

	Year Ended	
	December 31,	
	2016	2015
Australian Metallurgical Mining	\$ 4.36	\$ 5.27
Australian Thermal Mining	2.53	2.51
Powder River Basin Mining	0.71	0.69
Western U.S. Mining	0.92	0.93
Midwestern U.S. Mining	0.53	0.45

The decrease in depreciation, depletion and amortization expense during the year ended December 31, 2016 compared to the prior year reflected lower sales volumes from our mining platform. Depreciation, depletion and amortization was also impacted compared to the prior year by a reduction in the carrying value at certain of our Australian Metallurgical mines due to impairment charges recognized during 2015.

Selling and Administrative Expenses Related to Debt Restructuring. The general and administrative expenses related to debt restructuring recorded during the year ended December 31, 2016 related primarily to legal and other professional fees incurred in connection with debt restructuring initiatives prior to the Debtors' filing of the Bankruptcy Petitions.

Asset Impairment. We recognized \$247.9 million and \$1,277.8 million in aggregate asset impairment charges during the years ended December 31, 2016 and 2015, respectively. Refer to Note 4. "Asset Impairment" to the accompanying consolidated financial statements for further information regarding the nature and composition of those charges, which information is incorporated herein by reference.

Interest Expense. The decrease in interest expense for the year ended December 31, 2016 compared to the prior year is primarily due to the impact of our filing of the Bankruptcy Petitions, specifically only accruing adequate protection payments subsequent to the Petition Date to certain secured lenders and other parties in accordance with Section 502(b)(2) of the Bankruptcy Code, partially offset by increased interest recorded in connection with additional prepetition borrowings under the 2013 Revolver and increased expense related to additional letters of credit issued in support of various obligations.

Loss on Early Debt Extinguishment. The decrease in loss on early debt extinguishment charges for the year ended December 31, 2016 as compared to prior year was driven by higher charges recorded during the year ended December 31, 2015 related to the repurchase of \$566.9 million aggregate principal amount of our 2016 Notes compared to the charges recorded during the year ended December 31, 2016 related to the repayment of our DIP Term Loan Facility.

Reorganization Items, Net. The reorganization items recorded during the year ended December 31, 2016 related to expenses in connection with our Chapter 11 Cases. Refer to Note 2. "Reorganization Items, Net" to the accompanying consolidated financial statements for further information regarding our reorganization items.

Loss from Continuing Operations, Net of Income Taxes

The following table presents loss from continuing operations, net of income taxes, for the years ended December 31, 2016 and 2015:

	Year Ended		Increase	
	December 31,		(Decrease)	
	2016	2015	\$	%
	(Dollars in millions)			
Loss from continuing operations before income taxes	\$(758.3)	\$(1,990.3)	\$1,232.0	61.9 %
Income tax benefit	(84.0)	(176.4)	(92.4)	(52.4)%
Loss from continuing operations, net of income taxes	\$(674.3)	\$(1,813.9)	\$1,139.6	62.8 %

Results from continuing operations, net of income taxes, increased for the year ended December 31, 2016 compared to the prior year due to the effect of higher before-tax earnings, partially offset by the unfavorable effect of income taxes.

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Income Tax Benefit. The year-over-year unfavorable effect of income taxes was driven by higher benefits recorded in 2015 as compared to 2016 for the tax allocation to continuing operations related to the tax effects of items credited directly to "Accumulated other comprehensive loss", the release of reserves related to uncertain tax positions and the election to carry back specified liability losses ten years. These unfavorable factors were partially offset by lower expense in Australia due to reduced before-tax earnings in 2016 as compared to 2015. Refer to Note 12. "Income Taxes" to the accompanying consolidated financial statements for additional information.

Net Loss Attributable to Common Stockholders

The following table presents net loss attributable to common stockholders for the years ended December 31, 2016 and 2015:

	Year Ended December 31,		Increase (Decrease) to Income	
	2016	2015	\$	%
	(Dollars in millions)			
Loss from continuing operations, net of income taxes	\$(674.3)	\$(1,813.9)	\$1,139.6	62.8 %
Loss from discontinued operations, net of income taxes	(57.6)	(175.0)	117.4	67.1 %
Net loss	(731.9)	(1,988.9)	1,257.0	63.2 %
Net income attributable to noncontrolling interests	7.9	7.1	(0.8)	(11.3)%
Net loss attributable to common stockholders	\$(739.8)	\$(1,996.0)	\$1,256.2	62.9 %

Net results attributable to common stockholders increased during the year ended December 31, 2016 compared to the prior year largely due to the favorable change in results from continuing operations, net of income taxes, as discussed above, and the favorable impact of changes in results from discontinued operations.

Loss from Discontinued Operations, Net of Income Taxes. The improved results from discontinued operations for the year ended December 31, 2016 compared to the prior year was driven primarily by Patriot bankruptcy related charges associated with black lung liabilities and the UMWA Combined Benefit Fund totaling \$132.5 million recognized during 2015. Results for the year ended December 31, 2015 also reflected a \$34.7 million charge related to credit support that we provided to Patriot and a charge of \$9.7 million associated with the Queensland Bulk Handling Pty Ltd. litigation. These costs were partially offset by charges of \$54.3 million recorded during the year ended December 31, 2016 associated with the UMWA 1974 Pension Plan settlement. Those matters are discussed further in Note 26. "Commitments and Contingencies" and Note 27. "Matters Related to the Bankruptcy of Patriot Coal Corporation" to the accompanying consolidated financial statements.

Diluted EPS

The following table presents diluted EPS for the years ended December 31, 2016 and 2015:

	Year Ended December 31,		Increase to EPS	
	2016	2015	\$	%
Diluted EPS attributable to common stockholders:				
Loss from continuing operations	\$(37.30)	\$(100.34)	\$63.04	62.8%
Loss from discontinued operations	(3.15)	(9.64)	6.49	67.3%
Net loss	\$(40.45)	\$(109.98)	\$69.53	63.2%

Diluted EPS increased in the year ended December 31, 2016 compared to the prior year commensurate with the favorable change in results from continuing and discontinued operations between those periods.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Summary

Demand for seaborne metallurgical coal for the year ended December 31, 2015 was adversely impacted by a 2.5% decrease in worldwide steel production compared to the prior year, according to data published by the WSA. Policy measures in China aimed toward supporting the domestic coal industry also limited imports into China during 2015. Such measures, along with a lack of growth in global electricity generation from coal also hampered demand for seaborne thermal coal in 2015.

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These adverse demand factors and the impact of excess metallurgical and thermal supply continued to weigh on international coal prices. Benchmark pricing for seaborne premium HGHCC and premium LV PCI for 2015 and 2014 were as follows (on a per tonne basis):

Contract Commencement Month:	HGHCC Price			LV PCI Price		
	2015	2014	Decrease	2015	2014	Decrease
January	\$117	\$143	(18)%	\$99	\$116	(15)%
April	\$110	\$120	(8)%	\$93	\$100	(7)%
July	\$93	\$120	(23)%	\$73	\$100	(27)%
October	\$89	\$119	(25)%	\$71	\$99	(28)%

During the year ended December 31, 2015, HGHCC and Newcastle index thermal coal realized the following spot pricing:

	High	Low	Average	December 31, 2015
High quality hard coking coal	\$110	\$72	\$ 87	\$ 76
Newcastle index thermal coal	\$71	\$51	\$ 59	\$ 51

In the U.S., electricity generation from coal decreased 13% during the year ended December 31, 2015 compared to 2014, according to the U.S. EIA. U.S. electricity generation from coal was unfavorably affected during that period by coal-to-gas switching due to relatively lower natural gas prices and lower heating-degree days due to mild winter weather. Production in the U.S. Powder River Basin was also impacted by higher-than-average rainfall in the second quarter of 2015, which further contributed, along with the above factors, to a decrease in sales volumes in our total U.S. mining platform of 7% for the year ended December 31, 2015 compared to the prior year.

Our revenues decreased during the year ended December 31, 2015 compared to the prior year (\$1,183.0 million) primarily due to lower realized pricing and lower sales volumes driven by the demand and production factors mentioned above.

To mitigate the impact of lower coal pricing, we continued to drive operational efficiencies, optimize production across our mining platform and control expenses at all operational and administrative levels of the organization, which led to year-over-year decreases in our operating costs and expenses (\$709.2 million) and selling and administrative expenses (\$50.7 million). Also included in operating results for the year ended December 31, 2015 were aggregate restructuring charges of \$23.5 million, recognized in connection with certain actions initiated to reduce headcount and costs at several operating sites in Australia and to amend our administrative organizational structure.

Net loss attributable to common stockholders was \$1,996.0 million for the year ended December 31, 2015, an increase of \$1,209.0 million compared to the net loss attributable to common stockholders of \$787.0 million in the prior year. The increased loss reflected an adverse impact from asset impairment charges, a year-over-year decrease in Adjusted EBITDA and unfavorable results from discontinued operations. Those factors were partially offset by a favorable income tax variance.

As mentioned above, we recognized material impairments during the year ended December 31, 2015 (\$1,277.8 million). Additional information surrounding those charges may be found in Note 4. "Asset Impairment" to the accompanying consolidated financial statements.

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Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2015 and 2014:

	Year Ended		Decrease	
	December 31, 2015	December 31, 2014	Tons	%
	(Tons in millions)			
Australian Metallurgical Mining	15.7	17.2	(1.5)	(8.7)%
Australian Thermal Mining	20.1	21.0	(0.9)	(4.3)%
Powder River Basin Mining	138.8	142.6	(3.8)	(2.7)%
Western U.S. Mining	17.9	23.8	(5.9)	(24.8)%
Midwestern U.S. Mining	21.2	25.0	(3.8)	(15.2)%
Total tons sold from mining segments	213.7	229.6	(15.9)	(6.9)%
Trading and Brokerage	15.1	20.2	(5.1)	(25.2)%
Total tons sold	228.8	249.8	(21.0)	(8.4)%

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