UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2019
or

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

Commission File Number 1-16463

Peabody

PEABODY ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	13-4004153
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
701 Market Street, St. Louis, Missouri	63101-1826
(Address of principal executive offices)	*(Zip Code)*

(314) 342-3400
(Registrant's telephone number, including area code)

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

Title of Each Class	*Trading Symbol(s)*	*Name of Each Exchange on Which Registered*
Common Stock, par value $0.01 per share	BTU	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ 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 every Interactive Data File required to be submitted 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 such files). Yes ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐
Non-accelerated filer ☐ Smaller reporting company ☐
Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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, 2019: Common Stock, par value $0.01 per share, $1.9 billion.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

Number of shares outstanding of each of the Registrant's classes of Common Stock, as of February 18, 2020: Common Stock, par value $0.01 per share, 97,108,831 shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 2020 Annual Meeting of Shareholders (the Company's 2020 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements of our expectations, intentions, plans and beliefs that constitute “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act), 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:

- as a result of our emergence from our Chapter 11 Cases, our historical financial information is not indicative of our future financial performance;
- our profitability depends upon the prices we receive for our coal;
- if a substantial number of our long-term coal supply agreements terminate, or if the pricing, volumes or other elements of those agreements materially adjust, 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;
- the loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues;
- our trading and hedging activities do not cover certain risks and may expose us to earnings volatility and other risks;
- our operating results could be adversely affected by unfavorable economic and financial market conditions;
- our ability to collect payments from our customers could be impaired if their creditworthiness or contractual performance deteriorates;
- risks inherent to mining could increase the cost of operating our business, and events and conditions that could occur during the course of our mining operations could have a material adverse impact on us;
- if transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal may be diminished;
- 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;
- take-or-pay arrangements within the coal industry could unfavorably affect our profitability;
- an inability of trading, brokerage, mining or freight counterparties to fulfill the terms of their contracts with us could reduce our profitability;
- 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;
- our ability to operate our company effectively could be impaired if we lose key personnel or fail to attract qualified personnel;
- we could be negatively affected if we fail to maintain satisfactory labor relations;
- we could be adversely affected if we fail to appropriately provide financial assurances for our obligations;
- 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;
- 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;
- we may be unable to obtain, renew or maintain permits necessary for our operations, or we may be unable to obtain, renew or maintain such permits without conditions on the manner in which we run our operations, which would reduce our production, cash flows and profitability;
- 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;
- 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 future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable;

- we face numerous uncertainties in estimating our economically recoverable coal reserves and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability;
- our global operations increase our exposure to risks unique to international mining and trading operations;
- our proposed joint venture with Arch Coal, Inc. (Arch) may not be completed;
- joint ventures, partnerships or non-managed operations may not be successful and may not comply with our operating standards;
- we may undertake further repositioning plans that would require additional charges;
- 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 employees, our customers or other third-parties;
- our expenditures for postretirement benefit obligations could be materially higher than we have predicted if our underlying assumptions prove to be incorrect;
- concerns about the impacts of coal combustion on global climate are increasingly leading to consequences that have affected and could continue to affect demand for our products or our securities and our ability to produce, including increased governmental regulation of coal combustion and unfavorable investment decisions by electricity generators;
- numerous activist groups are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal, and potentially materially and adversely impacting our future financial results, liquidity and growth prospects;
- our financial performance could be adversely affected by our indebtedness;
- despite our indebtedness, we may still be able to incur substantially more debt, including secured debt, which could further increase the risks associated with our indebtedness;
- the terms of our indenture governing our senior secured notes and the agreements and instruments governing our other indebtedness impose restrictions that may limit our operating and financial flexibility;
- the number and quantity of viable financing alternatives available to us may be significantly impacted by unfavorable lending and investment policies by financial institutions and insurance companies associated with concerns about environmental impacts of coal combustion, and negative views around our efforts with respect to environmental and social matters and related governance considerations could harm the perception of our company by certain investors or result in the exclusion of our securities from consideration by those investors;
- the price of our securities may be volatile;
- our Common Stock is subject to dilution and may be subject to further dilution in the future;
- there may be circumstances in which the interests of a significant stockholder could be in conflict with other stakeholders' interests;
- the payment of dividends on our stock or repurchases of our stock is dependent on a number of factors, and future payments and repurchases cannot be assured;
- we may not be able to fully utilize our deferred tax assets;
- acquisitions and divestitures are a potentially important part of our long-term strategy, subject to our investment criteria, and involve a number of risks, any of which could cause us not to realize the anticipated benefits;
- our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt;
- diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results; and
- other risks and factors, including those discussed in "Legal Proceedings," set forth in Part I, Item 3 of this report and "Risk Factors," set forth in Part I, Item 1A of this report.

When considering these forward-looking statements, you should keep in mind the cautionary statements in this document and in our other Securities and Exchange Commission (SEC) filings. These forward-looking statements speak only as of the date on which such statements were made, and we undertake no obligation to update these statements except as required by federal securities laws.

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Note: The words "we," "us," "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 leading global pure-play coal company. As of December 31, 2019, we own interests in 21 coal mining operations located in the United States (U.S.) and Australia. We had previously reported owning interests in 23 coal mining operations, but during the year ended December 31, 2019, the Cottage Grove Mine in the Midwestern U.S. Mining segment and the Kayenta Mine in the Western U.S. Mining segment shipped their final tons. As a result, we now have a majority interest in 20 mining operations and a 50% equity interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia.

We also announced the closures of the Millennium, Wildcat HiIls Underground and Somerville Central Mines, with all of those operations expecting to ship their final tons in 2020. In the Midwestern U.S. Mining segment, we are continuing to transition toward operating complexes as we shift our sourcing of contracts to more productive mines.

In 2019, we achieved a global safety incidence rate of 1.64 incidents per 200,000 hours worked, which was 43% better than the 2018 industry average incidence rate of 2.88 incidents per 200,000 hours worked per the Mine Safety and Health Administration (MSHA).

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 the U.S., Australia, China and the United Kingdom.

In December 2019, after receiving the requisite regulatory and permitting approvals, we formed an unincorporated joint venture with Glencore plc (Glencore), in which we hold a 50% interest, to combine the existing operations of our Wambo Open-Cut Mine in Australia with the adjacent coal reserves of Glencore's United Mine. We will proportionally consolidate the entity based upon our economic interest. Glencore will manage the mining operations of the joint venture (United Wambo Joint Venture).

On June 18, 2019, we entered into a definitive implementation agreement (the Implementation Agreement) with Arch, to establish a joint venture that will combine the respective Powder River Basin (PRB) and Colorado operations of Peabody and Arch. We expect the joint venture to result in several operational synergies, including improved mining productivity and lower per-unit operating costs. Pursuant to the terms of the Implementation Agreement, we will hold a 66.5% economic interest in the joint venture and Arch will hold a 33.5% economic interest. We expect to proportionally consolidate the entity based upon our economic interest. Governance of the joint venture will be overseen by the joint venture's board of managers, which will be comprised of Peabody and Arch representatives with voting powers proportionate with the companies' economic interests, with the exception of certain specified matters which will require supermajority approval. We will manage the operations of the joint venture, subject to the supervision of the joint venture's board of managers.

Formation of the joint venture is subject to customary closing conditions, including the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, the receipt of certain other required regulatory approvals and the absence of injunctions or other legal restraints preventing the formation of the joint venture. The proposed joint venture is progressing through the U.S. Federal Trade Commission regulatory review process and we expect a decision in the first quarter, which would result in clearance to form the joint venture or litigation to block its execution. In September 2019, we amended our credit agreement to expressly permit formation of the joint venture and we are exploring various alternatives under the indenture governing our senior secured notes. At such time as control over the existing operations is exchanged, we will account for our interest in the combined operations at fair value.

Our current focus is on successfully integrating the United Wambo Joint Venture; progressing the PRB Colorado joint venture with Arch; evaluating commercial alternatives or mine development at our North Goonyella Mine; advancing mine life extension projects in seaborne segments; and maintaining financial strength.

Segment and Geographic Information

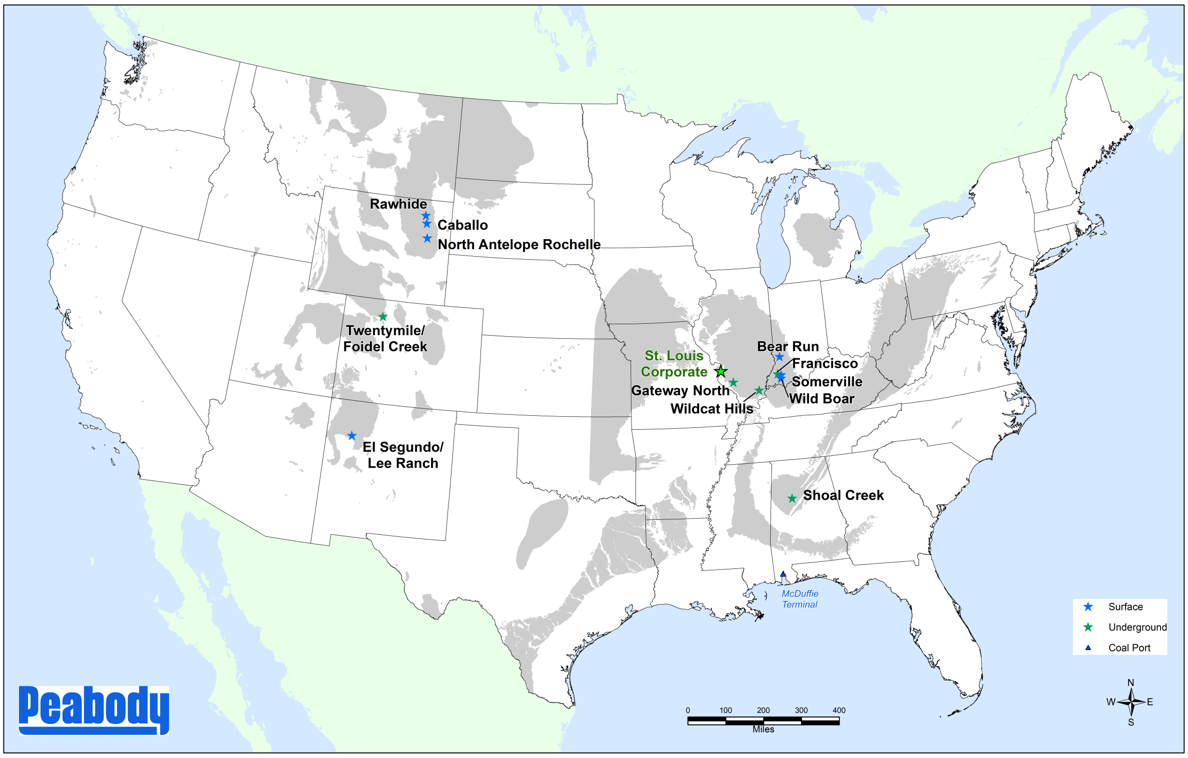
As of December 31, 2019, we report our results of operations primarily through the following reportable segments: Seaborne Thermal Mining, Seaborne Metallurgical Mining, Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining and Corporate and Other.

Refer to Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information regarding our segments. Note 28. “Segment and Geographic Information” to the accompanying consolidated financial statements is incorporated herein by reference and also contains segment and geographic financial information, including details of our plan to update our reportable segments beginning in the first quarter of 2020 to combine the Midwestern U.S. Mining segment with the Western U.S. Mining segment, which reflects the manner in which the chief operating decision maker (CODM) views our businesses going forward for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. Beginning the first quarter of 2020, we will report our results of operations primarily through the following reportable segments: Seaborne Thermal Mining, Seaborne Metallurgical Mining, Powder River Basin Mining, Other U.S. Thermal Mining and Corporate and Other.

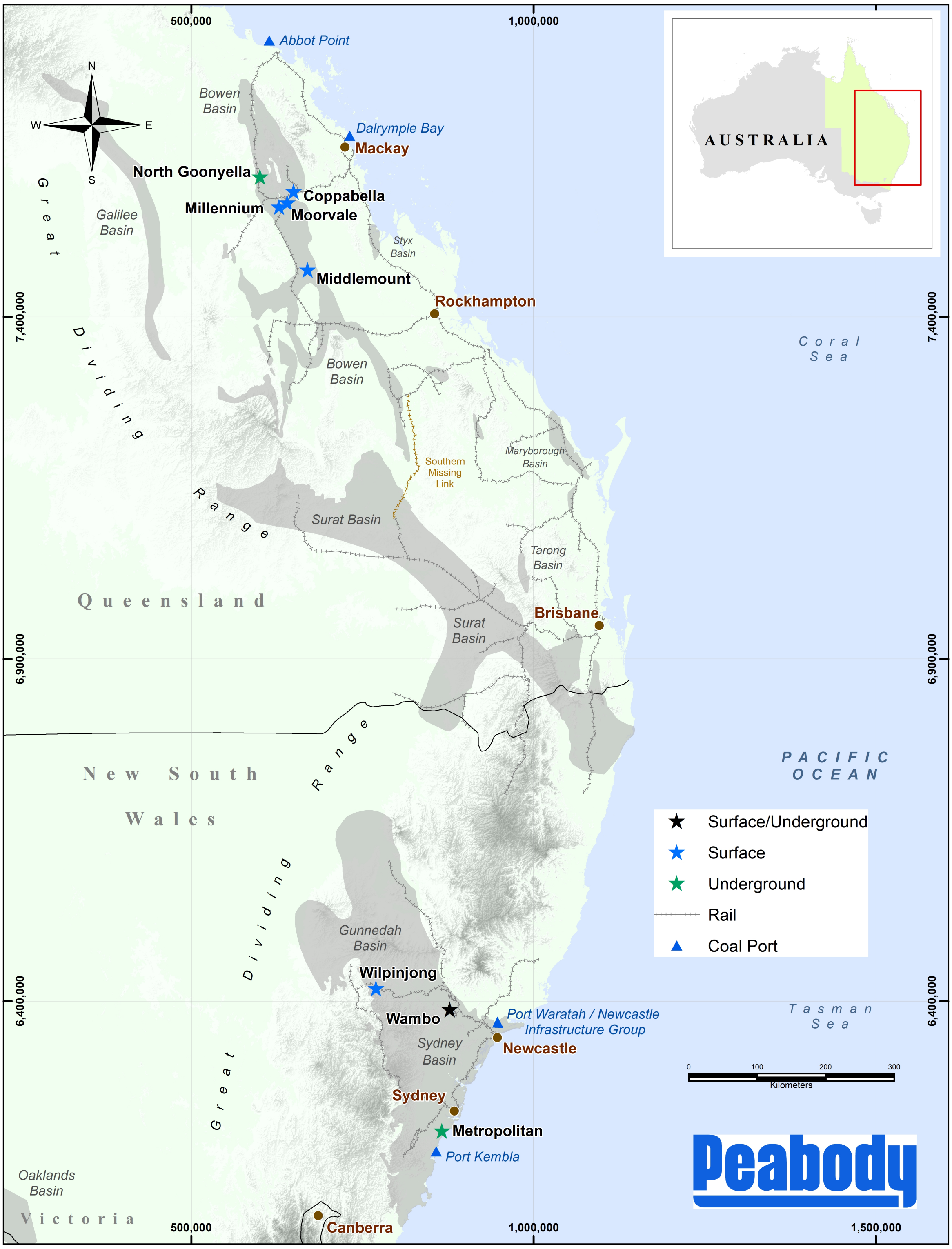
Mining Locations

The maps that follow display our active mine locations as of December 31, 2019. Also shown are the primary ports that we use for our coal exports and our corporate headquarters in St. Louis, Missouri.

U.S. Locations



Australian Locations



The table below summarizes information regarding the operating characteristics of each of our mines that were active in 2019 in the U.S. and Australia. The mines are listed within their respective mining segment in descending order, as determined by tons sold in 2019.

Segment/Mining Complex	Location	Mine Type	Mining Method	Coal Type	Primary Transport Method	2019 Tons Sold (In millions)
Seaborne Thermal Mining						
Wilpinjong	New South Wales	S	D, T/S	T	R, EV	14.0
Wambo Open-Cut (1)	New South Wales	S	T/S	T	R, EV	3.3
Wambo Underground (1)	New South Wales	U	LW	T, C	R, EV	2.2
Seaborne Metallurgical Mining						
Coppabella (2)	Queensland	S	DL, D, T/S	P	R, EV	2.2
Shoal Creek	Alabama	U	LW	C	B, EV	2.1
Moorvale (2)	Queensland	S	D, T/S	C, P, T	R, EV	1.6
Metropolitan	New South Wales	U	LW	C, P, T	R, EV	1.4
Millennium (3)	Queensland	S	HW	C, P	R, EV	0.7
North Goonyella (4)	Queensland	U	LW	C	R, EV	0.1
Middlemount (5)	Queensland	S	D, T/S	C, P	R, EV	—
Powder River Basin Mining						
North Antelope Rochelle	Wyoming	S	D, DL, T/S	T	R	85.3
Caballo	Wyoming	S	D, T/S	T	R	12.6
Rawhide	Wyoming	S	D, T/S	T	R	10.1
Third party (6)	—	—	—	—	—	0.1
Midwestern U.S. Mining						
Bear Run	Indiana	S	DL, D, T/S	T	Tr, R	6.3
Gateway North	Illinois	U	CM	T	Tr, R, R/B, T/B	3.0
Wild Boar	Indiana	S	D, T/S, HW	T	Tr, R, R/B, T/B	2.5
Francisco Underground	Indiana	U	CM	T	R	1.7
Wildcat Hills Underground (7)	Illinois	U	CM	T	T/B	1.3
Somerville Central (3)	Indiana	S	DL, D, T/S	T	R, R/B, T/B, T/R	1.1
Cottage Grove (8)	Illinois	S	D, T/S	T	T/B	0.1
Western U.S. Mining						
El Segundo/Lee Ranch	New Mexico	S	D, DL, T/S	T	R	5.4
Kayenta (9)	Arizona	S	DL, T/S	T	R	4.0
Twentymile	Colorado	U	LW	T	R, Tr	2.5

Legend:

S	Surface Mine	B	Barge
U	Underground Mine	Tr	Truck
HW	Highwall Miner	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
CM	Continuous Miner	C	Coking
R	Rail	P	Pulverized Coal Injection

(1) Majority-owned mines in which there is an outside non-controlling ownership interest.

(2) We own a 73.3% undivided interest in an unincorporated joint venture that owns the Coppabella and Moorvale mines. The tons shown reflect our share.

(3) It has been announced that the mine will close in 2020.

(4) Our North Goonyella Mine experienced a fire during September 2018. The tons shown reflect the remaining inventory that was sold during 2019.

(5) We own a 50% equity interest in Middlemount, which owns the Middlemount Mine. Because that entity is accounted for as an unconsolidated equity affiliate, 2019 tons sold from that mine, which totaled 2.9 million tons (on a 100% basis), have been excluded from the table above.

(6) Third-party purchased coal used to satisfy coal supply agreements.

(7) Mine ceased production in December 2019. The shipment of final tons is expected in 2020.

(8) Mine was closed in July 2019.

(9) Mine was closed in August 2019.

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.

Coal Supply Agreements

Customers. Our coal supply agreements are primarily with electricity generators, industrial facilities and steel manufacturers. Most of our sales from our mining operations 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 from our mining operations are made under contracts with terms of less than one year, including sales made on a spot basis. Sales under long-term coal supply agreements comprised approximately 88%, 87% and 83% of our worldwide sales from our mining operations (by volume) for the years ended December 31, 2019, 2018 and 2017, 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, 2019, we derived 33% of our revenues from coal supply agreements from our five largest customers. Those five customers were supplied primarily from 43 coal supply agreements (excluding trading and brokerage transactions) expiring at various times from 2020 to 2025. The customer contributing the greatest amount of annual revenue in 2019 was approximately $477 million, or approximately 11% of our 2019 total revenues from coal supply agreements, and has contracts expiring at various times from 2021 to 2023.

Backlog. Our sales backlog, which includes coal supply agreements subject to price reopener and/or extension provisions, was approximately 327 million and 401 million tons of coal as of January 1, 2020 and 2019, respectively. Contracts in backlog have remaining terms ranging from one to seven years and represent approximately two years of production based on our 2019 production volume of 164.7 million tons. Approximately 59% of our backlog is expected to be filled beyond 2020.

Seaborne Mining Operations. Revenues from our Seaborne Thermal Mining and Seaborne Metallurgical Mining segments represented approximately 45%, 48% and 46% of our total revenues from coal supply agreements for the years ended December 31, 2019, 2018 and 2017, respectively, during which periods the coal mining activities of those segments contributed respective amounts of 17%, 16% and 16% of our sales volumes from mining operations. Our production is primarily sold into the seaborne thermal and metallurgical 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 seaborne thermal coal contracts on an annual, spot or index basis and seaborne metallurgical coal contracts on a quarterly, spot or index basis. For our seaborne mining operations, the portion of sales volume under contracts with a duration of less than one year represented 29% in 2019.

U.S. Thermal Mining Operations. Revenues from our Powder River Basin Mining, Western U.S. Mining and Midwestern U.S. Mining segments, in aggregate, represented approximately 55%, 52% and 53% of our revenues from coal supply agreements for the years ended December 31, 2019, 2018 and 2017, respectively, during which periods the coal mining activities of those segments contributed respective aggregate amounts of approximately 83%, 84% and 84% of our sales volumes from mining operations. We expect to continue selling a significant portion of coal production from our U.S. thermal mining segments under long-term supply agreements, and customers of those segments generally favor 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 may vary 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 and terms and conditions we believe are favorable.

Transportation

Methods of Distribution. Coal consumed in the U.S. is usually sold at the mine with transportation costs borne by the purchaser. Our U.S. mine sites are typically adjacent to a rail loop; however, in limited circumstances coal may be trucked to a barge site or directly to customers. Title predominately passes to the purchaser at the rail or barge, as applicable. Our U.S. and Australian export coal is usually sold at the loading port, with purchasers paying ocean freight. In each case, we usually pay transportation costs from the mine to the port, including any demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time).

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

Export Facilities. Our seaborne mining operations sold approximately 71%, 75% and 73% of its tons into the seaborne coal markets for the years ended December 31, 2019, 2018 and 2017, respectively. We have generally secured our ability to transport coal in Australia through rail and port contracts and access to 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 thermal and metallurgical 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 thermal and metallurgical 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. We have secured our ability to transport coal from our Shoal Creek Mine under barge and port contracts; the primary port is the McDuffie Terminal in Mobile, Alabama, which we utilize without a take-or-pay arrangement.

Our U.S. thermal mining operations exported less than 1%, approximately 1% and approximately 1% of its annual tons sold for the years ended December 31, 2019, 2018 and 2017, respectively. The primary ports used for U.S. thermal 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.

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 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 situations where we have elected to concentrate a large portion of our purchases with one supplier, it has been to take advantage of cost savings from larger volumes of purchases, benefit from long-term pricing for parts, 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, enhancing our flexibility to move equipment between mines, and reduce working capital through inventory optimization.

Surface and underground mining equipment demand and lead times have remained steady in recent periods. We consistently 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, including wind, solar, oil, hydro, nuclear, natural gas and biomass; the impact of weather on heating and cooling demand; 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, demand for electricity, including the impact of energy efficient products, and the cost of electricity generation from coal and alternative forms of generation. Our products compete with producers of other forms of electricity 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. Regulatory policies and environmental, social and governance considerations can also have an impact on generation choices and coal consumption.

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 new natural gas combined cycle generation capacity as well as comparatively low natural gas prices (versus historic levels). The Henry Hub Natural Gas Prompt Price averaged $2.53 per mmBtu in 2019, versus $3.07 and $3.02 per mmBtu in 2018 and 2017, respectively. The growth in domestic natural gas production and logistical constraints has led to discounts for regional gas prices versus the Henry Hub price, further driving lower natural gas price trends. In addition, the competitiveness of other alternative fuel sources for electricity generation with coal has been strengthened by the growth of low-cost and government subsidized generation fueled by other alternative fuel sources. These pressures, coupled with increasing regulatory burdens, have contributed to a significant number of coal plant retirements. During 2019, approximately 14 gigawatts of U.S. coal power capacity was retired, and since 2010, U.S. coal power capacity has fallen by more than a quarter.

Internationally, thermal coal also competes with alternative forms of electricity generation. The competitiveness and availability of natural gas, oil, nuclear, hydro, wind, solar and biomass varies by country and region. Seaborne thermal coal consumption is also impacted by the competitiveness of delivered seaborne thermal coal supply from key exporting countries such as Indonesia, Australia, Russia, Colombia, the U.S. and South Africa, among others. In addition, seaborne thermal coal import demand can be significantly impacted by the availability of domestic coal production, particularly in the two leading coal import countries, China and India, 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, Arch, CONSOL Energy, Eagle Specialty Materials LLC, Murray Energy Corporation and Navajo Transitional Energy Company LLC, among others. Major international direct coal supply competitors (listed alphabetically) include Anglo American plc, BHP, China Shenhua Energy, Coal India Limited, Drummond Company, Glencore, PT Adaro Energy Tbk, SUEK, Whitehaven Coal Limited and Yancoal Australia Ltd, among others.

Metallurgical Coal

Demand for our metallurgical coal products is impacted by economic conditions, government policies, demand for steel and 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 domestic coal production, particularly in leading metallurgical coal import countries such as China, among others, and the competitiveness of seaborne metallurgical coal supply, including from leading metallurgical coal exporting countries of Australia, the U.S., Russia, Canada, Mongolia and Mozambique, among others.

Major international direct competitors (listed alphabetically) include Anglo American, BHP, Glencore, Jellinbah, KRU, Shanxi Coking Coal Group, Teck Resources, Whitehaven Coal Limited and Yancoal Australia Ltd and , among others.

Cybersecurity Risk Management

We use digital technology to conduct our business operations and engage with our customers, vendors and partners. As we implement newer technologies such as cloud, analytics, automation and “internet of things”, the threats to our business operations from cyber intrusions, denial of service attacks, manipulation and other cyber misconduct increase. To address the risk, we continue to evolve our risk management approach in an effort to continually assess and improve our cybersecurity risk detection, deterrence and recovery capabilities. Our cybersecurity strategy emphasizes reduction of cyber risk exposure and continuous improvement of our cyber defense and resilience capabilities. These include: (i) proactive management of cyber risk to ensure compliance with contractual, legal and regulatory requirements, (ii) performing due diligence on third parties to ensure they have sound cybersecurity practices in place, (iii) ensuring essential business services remain available during a business disruption, (iv) implementing data policies and standards to protect sensitive company information and (v) exercising cyber incident response plans and risk mitigation strategies to address potential incidents should they occur. For more information regarding the risks associated with these matters, see “Item 1A. Risk Factors.”

Working Capital

We generally fund our working capital requirements through a combination of existing cash and cash equivalents and proceeds from the sale of our coal production to customers. Our current accounts receivable securitization program and revolving credit facility are also available to fund our working capital requirements to the extent we have remaining availability. 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 6,600 employees as of December 31, 2019, including approximately 5,000 hourly employees. Additional information on our employees and related labor relations matters is contained in Note 24. “Management — Labor Relations” to the accompanying consolidated financial statements, which information is incorporated herein by reference.

Information About Our Executive Officers

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	52	President and Chief Executive Officer
Mark A. Spurbeck	46	Interim Chief Financial Officer
A. Verona Dorch	52	Executive Vice President, Chief Legal Officer, Governmental Affairs and Corporate Secretary
Charles F. Meintjes	57	Executive Vice President and Chief Operating Officer
Paul V. Richard	60	Senior Vice President and Chief Human Resources Officer
Marc E. Hathhorn	49	President - Australian Operations
Kemal Williamson	60	President - U.S. Operations

(1) As of February 18, 2020.

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’s career experience enables him to provide the Company with valuable insights from miner, competitor fuel and industrial customer perspectives. From 1985 to 2013, he worked for BHP Ltd. in the United States, Australia and South America. Mr. Kellow has held chief executive leadership, operating and financial roles in global business in the coal, copper, nickel, aluminum, steel, oil and gas sectors. He serves as Chairman of the World Coal Association, a director and executive committee member of the U.S. National Mining Association and the Vice Chairman of the International Energy Agency Coal Industry Advisory Board. Mr. Kellow is a graduate of the Advanced Management Program at the University of Pennsylvania’s Wharton School of Business, holds a Master of Business Administration Degree and a Bachelor’s Degree in Commerce from the University of Newcastle. He also holds an honorary Doctor of Science degree from the South Dakota School of Mines and Technology.

Mark A. Spurbeck was named our Interim Chief Financial Officer in January 2020. Mr. Spurbeck has more than 20 years of accounting and financial experience, most recently serving as the Company’s Senior Vice President and Chief Accounting Officer since March 2018. In this role, he has overseen Peabody’s finance, treasury, tax, internal audit, financial reporting and corporate accounting functions. Prior to joining Peabody, Mr. Spurbeck served as Vice President of Finance and Chief Accounting Officer at Coeur Mining, Inc., a diversified precious metals producer, from March 2013 to January 2018. He also previously held multiple financial positions at Newmont Mining Corporation, a leading gold and copper producer, including Group Executive, Assistant Controller. Mr. Spurbeck also previously served in several financial positions at First Data Corporation, a financial services company, and Deloitte LLP, an international accounting, tax and advisory firm. Mr. Spurbeck is a Certified Public Accountant and holds a Bachelor’s Degree in Accounting from Hillsdale College.

A. Verona Dorch was named our Executive Vice President, Chief Legal Officer, Governmental Affairs and Corporate Secretary in August 2015. In this role, she has executive responsibility for providing comprehensive legal and government relations counsel for Peabody’s business activities and leads the Company’s global legal, government affairs and compliance functions. Ms. Dorch has close to 25 years of legal experience counseling diverse global businesses. Prior to joining Peabody, from 2006 to March 2015, she served in a variety of roles for Harsco Corporation, a leading global industrial services company, where she advised the leadership team and board on strategic legal and business initiatives, most recently serving as Chief Legal Officer, Chief Compliance Officer and Corporate Secretary. She also has experience in corporate and securities law from top-tier law firms and with Sumitomo Chemical Co. following a multi-year secondment in Tokyo, Japan. Ms. Dorch is a Fellow of the American Bar Foundation and is a member of the board of directors of Enterprise Bank & Trust, a regional bank with over $5.5 billion in assets, and is a member of the boards of directors of Girls Inc. (St. Louis) and the United Way (St. Louis). Ms. Dorch holds a Bachelor’s Degree from Dartmouth College and a Juris Doctor degree from Harvard Law School.

Charles F. Meintjes was named our Executive Vice President - Corporate Services and Chief Commercial Officer in April 2017 and our Executive Vice President and Chief Operating Officer in July 2019. Mr. Meintjes has executive responsibility for operations, sales and marketing and technical services. Mr. Meintjes has extensive senior operational, strategy, continuous improvement and information technology experience with mining companies on three continents. He has also led financial and technical functions, large re-engineering programs, information technology system implementations and large industrial construction projects. He joined us in 2007, and prior to serving in his current post, he was our President - Australia. Other past positions with us include Acting President - Americas, 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 has senior management experience in the steel and the aluminum industries 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.

Paul V. Richard was named our Senior Vice President and Chief Human Resources Officer in November 2017. He has executive responsibility for organizational and employee development, benefits, compensation, international human resources, security, travel and facilities management. Mr. Richard has more than 30 years of human resources experience and has been instrumental in leading his prior organizations to achieve Great Place to Work and Top Training Organization designations. From 2002 to May 2017, Mr. Richard served as Vice President - Human Resources for Shaw Industries Group, Inc., a leading flooring materials producer and a subsidiary of Berkshire Hathaway, Inc. Prior to that, he served as a human resources leader for 19 years at Ferro Corporation, a global supplier of technology-based manufacturing, including four years as Vice President - Human Resources. Mr. Richard holds a Bachelor of Science Degree in Management and a Masters of Business Administration Degree from Louisiana Tech University.

Marc E. Hathhorn was named our President - Australian Operations in August 2019. He has executive responsibility for our Australian operating platform, which includes overseeing the areas of health and safety, operations, product delivery and support functions. Mr. Hathhorn has more than 30 years of experience in mining engineering and operations in North and South America. Mr. Hathhorn joined us in 2011 as our Senior Vice President - Midwest Operations, and subsequently served as our Group Executive - Americas Operations Support from 2013 to 2016, and Group Executive - Americas Operations from 2016 until assuming his current role. Previously, Mr. Hathhorn held various leadership positions with Drummond LTD in South America, including Mine Operations Superintendent, Port Manager, and Vice President - Mining Operations. Prior to joining Drummond LTD, Mr. Hathhorn held various engineering and supervisory positions with Newmont Gold Corporation. Mr. Hathhorn holds a Bachelor of Science Degree in Mining Engineering from the University of Idaho, College of Mines.

Kemal Williamson was named our President - Americas in October 2012 and his title was updated to President - U.S. Operations in June 2019. 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 of 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.

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 (collectively with Peabody, the Debtors) filed voluntary petitions for reorganization under Chapter 11 of Title 11 of the U.S. Code in the U.S. Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). The Debtors' Chapter 11 cases (collectively, the Chapter 11 Cases) were jointly administered under the caption *In re Peabody Energy Corporation, et al.*, Case No. 16-42529 (Bankr. E.D. Mo.).

On March 17, 2017, the Bankruptcy Court entered an order, Docket No. 2763, confirming the Debtors' Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, the Plan). On April 3, 2017 (the Effective Date), the Debtors satisfied the conditions to effectiveness set forth in the Plan, the Plan became effective in accordance with its terms and the Debtors emerged from the Chapter 11 Cases.

On March 22, 2017, a group of creditors (the Ad Hoc Committee) that held certain interests in the Company's prepetition indebtedness appealed the Bankruptcy Court's order confirming the Plan, requesting that the United States District Court for the Eastern District of Missouri (the District Court) reverse the Bankruptcy Court's confirmation of the Plan and the order approving the Private Placement Agreement and Backstop Commitment Agreement. On December 29, 2017, the District Court entered an order dismissing the Ad Hoc Committee's appeal, and, in the alternative, affirming the order confirming the Plan. On January 26, 2018, the Ad Hoc Committee appealed the District Court's order to the United States Court of Appeals for the Eighth Circuit (the Eighth Circuit). In its appeal, the Ad Hoc Committee asked the Eighth Circuit to award the Ad Hoc Committee members either unspecified damages or the right to buy an unspecified amount of Company stock at a discount. Oral argument on the appeal was held April 16, 2019, and the Eighth Circuit issued a unanimous opinion in Peabody's favor on August 9, 2019. The Ad Hoc Committee did not seek rehearing or petition the Supreme Court for certiorari by the deadline of November 7, 2019.

Upon emergence, in accordance with Accounting Standards Codification (ASC) 852, we applied fresh start reporting to our consolidated financial statements as of April 1, 2017 and became a new entity for financial reporting purposes reflecting the Successor (as defined below) capital structure. As a new entity, a new accounting basis in the identifiable assets and liabilities assumed was established with no retained earnings or accumulated other comprehensive income (loss). For additional details, refer to Note 1. "Summary of Significant Accounting Policies" and Note 2. "Reorganization Items" to the accompanying consolidated financial statements.

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 requirements 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.

The MSHA is the entity responsible for monitoring compliance with the federal mine health and safety standards. MSHA employs various enforcement measures for noncompliance, including the issuance of monetary penalties and orders of withdrawal from a mine or part of a mine.

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.

Black Lung (Coal Workers' 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 who was the last to employ a claimant for a cumulative year of employment, with the last day worked for the operator after July 1, 1973, must pay federal black lung benefits and medical expenses to claimants 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 has been funded by an excise tax on U.S. production. In 2008, the excise tax rates were set through December 31, 2018 at $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. On January 1, 2019 the rate reverted back to $0.50 per ton of underground coal and $0.25 per ton of surface coal, not to exceed 2% of the gross sales price. In December of 2019, legislation was passed that increased the rate for the year ending December 31, 2020. The enacted legislation mandates the previous rates of $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.

We recognized expense related to the tax of $31.4 million, $78.6 million, $60.9 million and $20.1 million for the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively.

The Affordable Care Act includes significant changes to the federal black lung program including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program.

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 (OSMRE), established mining, environmental protection and reclamation standards for surface mining and underground mining. Mine operators must obtain SMCRA permits and permit renewals for mining operations from the OSMRE or from the respective state regulatory authority. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the primary regulatory authority, with oversight from OSMRE. Except for Arizona, states in which we have active mining operations have achieved primacy control of enforcement through federal authorization. In Arizona, we mine on tribal lands and are regulated by the OSMRE 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 $1,263.9 million as of December 31, 2019. 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 or OSMRE. Our asset retirement obligations calculated in accordance with generally accepted accounting principles for our U.S. operations were $527.9 million as of December 31, 2019. 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 projected to be a number of years away. The bond amount, in contrast with the asset retirement obligation, presumes reclamation begins immediately.

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.

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

The SMCRA Abandoned Mine Land Fund requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund created by the Coal Industry Retiree Health Benefit Act of 1992. The fee amount can change periodically based on changes in federal legislation. Pursuant to the Tax Relief and Health Care Act of 2006, 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 $36.5 million, $40.9 million, $31.6 million and $10.3 million for the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, 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), nitrogen dioxide, ozone and sulfur dioxide (SO_2). In recent years, the United States Environmental Protection Agency (EPA) has adopted more stringent national ambient air quality standards (NAAQS) for PM, nitrogen oxide, ozone and SO_2. It is possible that these modifications, as well as future modifications to NAAQS, could directly or indirectly impact our mining operations in a manner that includes, but is not limited to, designating new nonattainment areas or expanding existing nonattainment areas, serving as a basis for changes in vehicle emission standards or prompting additional local control measures pursuant to state implementation plans required to address revised NAAQS.

In 2009, the EPA 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 in 2012. In 2015, the EPA issued a final rule setting the ozone NAAQS at 70 parts per billion (ppb). (80 Fed. Reg. 65,292 (Oct. 25, 2015)). The primary ozone standard was upheld by the United States Court of Appeals for the D.C. Circuit (D.C. Circuit) in *Murray Energy v. EPA*, (D.C. Cir. 2019), *Slip Op.* 15-1385. The court, however, remanded the secondary ozone NAAQS standard to the EPA and vacated a “grandfathering” provision concerning the use of the prior ozone NAAQS in certain permitting actions.

The EPA is additionally considering revisions to the 2015 PM NAAQS as part of the periodic review process required by the CAA, with any revisions to the standards projected for late 2020, the same timeframe as it contemplates possible revisions for the 2015 ozone NAAQS. More stringent PM or ozone standards would require new state implementation plans to be developed and filed with the EPA and may trigger additional control technology for mining equipment or result in additional challenges to permitting and expansion efforts. This could also be the case with respect to the implementation for other NAAQS for nitrogen oxide and SO_2 although the EPA promulgated a final rule on March 18, 2019 (84 Fed. Reg. 9866) that retains, without revision, the existing NAAQS for SO_2 of 75 ppb averaged over an hour.

The CAA also indirectly, but significantly affects the U.S. coal industry by extensively regulating the air emissions of SO_2, 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 (CSAPR) and the CSAPR Update 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.

In addition, since 2011, the EPA has required underground coal mines to report on their greenhouse gas emissions. Regulations regarding reporting requirements for underground coal mines were updated in 2016 and now include the ability to cease reporting if mines are abandoned and sealed. At present, however, the EPA does not directly regulate such emissions.

Final NSPS for Fossil Fuel-Fired Electricity Utility Generating Units (EGUs). The EPA promulgated a final rule to limit carbon dioxide (CO_2) from new, modified and reconstructed fossil fuel-fired EGUs under Section 111(b) of the CAA on August 3, 2015, and published it in the Federal Register on October 23, 2015.

This rule requires that newly-constructed fossil fuel-fired steam generating units achieve an emission standard for carbon dioxide of 1,400 lb carbon dioxide per megawatt-hour gross output (CO_2/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 best operating practices and equipment upgrades, to meet an emission standard consistent with best historical performance. Reconstructed units must implement the most efficient generating technology based on the size of the unit (supercritical steam conditions for larger units, to meet a standard of 1,800 lb CO_2/MWh-gross, and subcritical conditions for smaller units to meet a standard of 2,000 lb CO_2/MWh-gross).

Numerous legal challenges to the final rule were filed in the D.C. Circuit. Sixteen separate petitions for review were filed, and the challengers include 25 states, utilities, mining companies (including Peabody), labor unions, trade organizations and other groups. The cases were consolidated under the case filed by North Dakota (D.C. Cir. No. 15-1381). 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.” Pursuant to an order of the court, these cases remain in abeyance, subject to requirements for the EPA to file 90-day status reports. Thus, the NSPS remains in effect.

On December 6, 2018, the EPA proposed to revise the 2015 NSPS to modify the minimum requirements for newly constructed coal-fired units from partial carbon capture and storage to efficiency-based standards. The proposal now defines the Best System of Emission Reduction (BSER) as the most efficient demonstrated steam cycle in combination with the best operating practices. The EPA has noted that the primary reason for this proposed revision is the high costs and limited geographic availability of carbon capture and storage technology. The comment period on the proposed rule concluded on February 19, 2019.

EPA Regulation of Greenhouse Gas Emissions from Existing Fossil Fuel-Fired EGUs. On October 23, 2015, the EPA published a final rule in the Federal Register regulating greenhouse gas emissions from existing fossil fuel-fired EGUs under Section 111(d) of the CAA (80 Fed. Reg. 64,662 (Oct. 23, 2015)). The rule (known as the Clean Power Plan or CPP) established emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel-fired EGUs. The CPP required that the states individually or collectively create systems that would reduce carbon emissions from any EGU located within their borders by 28% in 2025 and 32% in 2030 (compared with a 2005 baseline).

Following Federal Register publication, 39 separate petitions for review of the CPP by approximately 157 entities were filed in the D.C. Circuit. The petitions reflected challenges by 27 states and governmental entities, as well as by utilities, industry groups, trade associations, coal companies and other entities. The lawsuits were consolidated with the case filed by West Virginia and Texas (in which other states also joined) (D.C. Cir. No. 15-1363). 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 other entities also intervened in support of the EPA.

On February 9, 2016, the U.S. Supreme Court granted a motion to stay implementation of the CPP until the legal challenges were resolved. Thereafter, oral arguments in the case were heard in the D.C. Circuit sitting en banc. On April 28, 2017, the D.C. Circuit granted the EPA's motion to hold the case in abeyance while the agency reconsidered the rule. The D.C. Circuit case has been in abeyance since, so no opinion has been issued.

In October 2017, the EPA proposed to repeal the CPP. (82 Fed. Reg. 48,035 (Oct. 16, 2017)). In August 2018, the EPA issued a proposed rule to replace the CPP, the Affordable Clean Energy (ACE) Rule. (83 Fed. Reg. 44,746 (August 31, 2018)). On June 19, 2019, the EPA issued a combined package that finalizes the CPP repeal rule as well as the replacement rule, ACE. Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, EPA-HQ-OAR-2017-0355.

The final ACE rule sets emissions guidelines for greenhouse gas emissions from existing EGUs based on using efficiency heat rate improvements as "Best System of Emission Reduction" measures. The EPA's final rule also revises the CAA Section 111(d) regulations to give the states greater flexibility on the content and timing of their state plans. Proposed revisions to the regulations under the New Source Review (NSR) program that were part of the ACE proposal were separated, and the EPA indicated that it intends to take final action on the proposed NSR program reforms at a later date.

Based on the EPA's final rules repealing and replacing the CPP, petitioners in the D.C. Circuit matter seeking review of CPP, including Peabody, filed a motion to dismiss, which the court granted in September 2019. Meanwhile, challengers to the ACE Rule have filed petitions for judicial review, and that new litigation is expected to continue into 2020.

EPA's Greenhouse Gas Permitting Regulations for Major Emission Sources. In May 2010, the EPA published final rules requiring permitting and control technology requirements for greenhouse gases under the Prevention of Significant Deterioration (PSD) and Title V permitting programs that apply to stationary sources of air pollution. The EPA determined that these requirements were "triggered" by the EPA's prior regulation of greenhouse gases from motor vehicles. These rules were subsequently upheld by the D.C. Circuit on June 26, 2012. On June 23, 2014, however, the U.S. Supreme Court ruled that the EPA could not require PSD and Title V permitting for greenhouse gases emitted from stationary sources if those sources were not otherwise considered to be "major sources" of conventional pollutants for purposes of PSD and Title V (known as Step 2 sources). In accordance with that decision, the D.C. Circuit vacated the federal regulations that implemented Step 2 of the Greenhouse Gas Tailoring Rule in 2015. Subsequently, the EPA removed the vacated elements from its rules to ensure that neither the PSD nor Title V rules require a source to obtain a permit solely because the source emits or has the potential to emit greenhouse gases above the applicable thresholds. The EPA therefore no longer has the authority to conduct PSD permitting for Step 2 sources, nor can the EPA approve provisions submitted by a state for inclusion in its state implementation plan (SIP) providing this authority.

Cross State Air Pollution Rule (CSAPR) and CSAPR Update Rule. 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 reduce power plant emissions that cross state lines and significantly contribute to ozone and/or fine particle pollution in other states. Following litigation in the D.C. Circuit and U.S. Supreme Court, the first phase of the nitrogen oxide and SO_2 emissions reductions required by CSAPR commenced in January 2015; further reductions of both pollutants in the second phase of CSAPR became effective in January 2017. The EPA subsequently revised CSAPR requirements for the state of Texas to remove that state from second phase requirements regarding SO_2 (82 Fed. Reg. 45,481 (Sept. 29, 2017)).

On October 26, 2016, the EPA published the final CSAPR Update Rule to address implementation of the 2008 ozone NAAQS. This rule imposed further reductions in nitrogen oxides emissions beginning in 2017 in 22 states subject to CSAPR. Several states and utilities as well as agricultural and industry groups filed petitions for review of the CSAPR Update Rule in the D.C. Circuit. On September 13, 2019, the CSAPR Update Rule was subsequently remanded to the EPA to address the court's holding that the rule unlawfully allows significant contribution to continue beyond downwind attainment deadlines. *Wisconsin v. EPA*, No. 16-1406 (D.C. Cir. 2019). At this time, it is unknown whether rehearing will be sought.

In 2018, the EPA also issued a final determination that the existing CSAPR Update fully addressed the CAA's "good neighbor" requirements for 20 states with respect to the 2008 NAAQS for ground-level ozone. (83 Fed. Reg. 65,878 (Dec. 21, 2018)).This determination was also challenged in the D.C. Circuit (No. 19-1019). On October 1, 2019, the D.C. Circuit issued a judgment vacating this rule on the basis of the court's decision in *Wisconsin v. EPA*. At this time, it is unknown whether rehearing will be sought.

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, SO_2 and PM for new and modified coal-fueled electricity generating plants, and imposed MACT emission limits on hazardous air pollutants (HAPs) from new and existing coal-fueled and oil-fueled electric generating plants. MACT standards limit emissions of mercury, acid gas HAPs, non-mercury HAP metals and organic HAPs. The rule provided three years for compliance with MACT standards and a possible fourth year if a state permitting agency determined that such was necessary for the installation of controls.

Following issuance of the final rule, numerous petitions for review were filed. The D.C. Circuit upheld the NSPS portion of the rulemaking in a unanimous decision on March 11, 2014, and upheld the limits on HAPs against all challenges on April 15, 2014, in a two-to-one decision. Industry groups and a number of states filed and were granted review of the D.C. Circuit decision in the U.S. Supreme Court. On June 29, 2015 the U.S. Supreme Court held that the EPA interpreted the CAA unreasonably when it deemed cost irrelevant to the decision to regulate HAPs from power plants. The court reversed the D.C. Circuit and remanded the case for further proceedings. On December 1, 2015, in response to the court's decision the EPA published a proposed supplemental finding in the Federal Register that consideration of costs does not alter the EPA's previous determination regarding the control of HAPs in the MATS rule. On December 15, 2015, the D.C. Circuit issued an order providing that the rule will remain in effect while the EPA responds to the U.S. Supreme Court decision.

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 (D.C. Cir. No. 116-1127). Several states and environmental groups also filed as intervenors for the respondent EPA. Although briefing in this litigation has concluded, the case remains in abeyance.

On December 27, 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS rule that would revoke the determination that regulating HAPs from coal-fired power plants is "appropriate and necessary" under Section 112(n)(1)(A) of the CAA. The new proposed finding was based on an EPA assessment that health and environmental benefits from the MATS rule that are not directly related to mercury pollution should not be included in the benefit portion of the analysis. In the new proposed cost-benefit analysis, the EPA found the costs "grossly outweigh" any possible benefits. The comment period for this proposed rule closed in spring 2019 with over a half million public comments filed. The final rule was expected in the fall but stalled after being sent to the White House in October 2019 for final review before public release. It is unclear when the final rule will be published.

The EPA Science Advisory Board, made up of non-EPA scientists and experts who review the EPA's basis for regulatory decisions, recommended in December 2019 that the EPA conduct a new risk assessment concerning the rule.

The plan would leave the emissions standards of the MATS rule in effect but would repeal the statutorily required finding that it was "appropriate and necessary" to originally issue the standards. Many argue this could lead to industry lawsuits aimed at fully eliminating the standards.

Federal Coal Leasing Moratorium. President Trump's Executive Order on Promoting Energy Independence and Economic Growth (EI Order), signed on March 28, 2017, lifted the Department of Interior's federal coal leasing moratorium and rescinded guidance on the inclusion of social cost of carbon in federal rulemaking. Following the EI Order, the Interior Secretary issued Order 3349 ending the federal coal leasing moratorium. Environmental groups took the issue to court and in September 2018, Wyoming and Montana opposed the suits in court and defended against the freeze possibly being reinstated. This litigation is ongoing.

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 permits from the Corps to place material in or mine through jurisdictional waters of the U.S.

States are empowered to develop and apply 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. Standards vary from state to state. Additionally, through the CWA Section 401 certification program, state and tribal regulators have approval authority over federal permits or licenses that might result in a discharge to their waters. State and tribal regulators consider whether the activity will comply with their water quality standards and other applicable requirements in deciding whether or not to certify the activity. On August 9, 2019, the EPA issued a proposed rule intended to clarify the scope of the state or tribal regulators' authority that, if adopted in its current form, would in effect limit state and tribal regulators' authority by allowing the EPA to certify projects over state or tribal regulator objections. The comment period for this proposed rule closed on October 21, 2019.

A final rule defining the scope of waters protected under the CWA (commonly called the Waters of the United States, or WOTUS) (WOTUS Rule), was published by the EPA and the Corps in June 2015. Several states and others subsequently filed lawsuits challenging the WOTUS Rule. On October 22, 2019, the EPA and the Corps jointly published a final rule, which became effective on December 23, 2019, repealing the WOTUS Rule and recodifying the regulatory definitions of WOTUS that existed prior to the implementation of the WOTUS Rule. Several states subsequently filed a lawsuit against the EPA, claiming that the rollback of protections for certain U.S. waterways pursuant to the final rule is arbitrary, capricious and not in accordance with law. On January 23, 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule to define "Waters of the United States" and thereby establish federal regulatory authority under the CWA. The final rule will become effective 60 days after publication in the Federal Register. Once effective, it replaces the rule published on October 22, 2019.

Effluent Limitations Guidelines for the Steam Electric Power Generating Industry. On September 30, 2015, the EPA published a final rule setting new or additional requirements for various wastewater discharges from steam electric power plants. The rule set zero discharge requirements for some waste streams, as well as new, more stringent limits for arsenic, mercury, selenium and nitrogen applicable to certain other waste streams. On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit agreed with environmental groups that the portions of the rule regulating legacy wastewater and residual combustion leachate are unlawful. The Court vacated those portions of the rule. On November 22, 2019, the EPA issued a proposed rule to revise the technology-based effluent limitations guidelines and standards for the steam electric power generating point source category applicable to flue gas desulfurization wastewater and bottom ash transport water. The comment period for this proposed rule closed on January 21, 2020. If the proposed rule is adopted in its current form, the effluent limitations guidelines will significantly increase costs for many coal-fired steam electric power plants.

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. The White House Council on Environmental Quality (CEQ) issued an Advance Notice of Proposed Rulemaking in June 2018 seeking comment on a number of ways to streamline and improve the NEPA process. The comment period closed in August 2018. It is unclear how far reaching the changes will be and if they will be able to withstand expected court challenges.

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. The U.S. Court of Appeals for the D.C. Circuit held that certain provisions of the EPA's CCR rule were not sufficiently protective, and it invalidated those provisions. On December 2, 2019, the EPA issued a proposed rule to implement amended rules regarding CCR in response to the court decisions. The comment period for this proposed rule closed on January 31, 2020. Generally EPA-imposed requirements will increase the cost of CCR management, but not as much as if the rule had regulated CCR as hazardous

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. The Department of the Interior issued three proposed rules in 2018 aiming to streamline and update the ESA. The three final rules became effective on September 26, 2019.

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. On July 30, 2019, the OSMRE officially withdrew its decision to initiate rulemaking related to emissions generated from blasting at coal mining operations. The decision cited its lack of statutory authority and the sufficiency of the existing regulatory framework.

Grid Resiliency Pricing Rule. On October 10, 2017, the Secretary of Energy (the Secretary) published a Notice of Proposed Rulemaking entitled the Grid Resiliency Pricing Rule (the Proposed Rule). The Proposed Rule was issued by the Secretary pursuant to Section 403 of the Department of Energy Organization Act. (42 U.S.C. § 7173). In the Proposed Rule, the Secretary instructed the Federal Energy Regulatory Commission (FERC) to impose rules to ensure that reliability and resiliency attributes of certain electric generation units with a 90-day on-site fuel supply are fully compensated for the benefits and services they provide to grid operations. The Secretary directed FERC to take final action on the Proposed Rule within 60 days of publication or, in the alternative, to issue the rule as an interim final rule immediately, with provision for later modifications after consideration of public comments. The Proposed Rule cites the retirements of coal and nuclear plants as a potential threat to grid reliability and resilience, and provides for the creation of a "reliability and resiliency rate" that would compensate certain eligible resources for the benefits and services they provide to grid operations, allowing such eligible resources to recover their fully allocated costs and a fair return on equity. The "reliability and resiliency rate" would be available to eligible resources operating within FERC-approved independent system operators or regional transmission organizations with energy and capacity markets. The rate would apply only to generators that are not currently subject to cost-of-service regulation by a state or other authority. On January 8, 2018, FERC unanimously denied the petition and requested additional information from power grid operators thus putting off any new rulemaking by at least two months, dismissing the Secretary's call to act immediately. FERC has opened a new proceeding to "take additional steps to explore resilience issues in the [regional transmission organizations and independent system operators]." That docket will aim to develop an understanding of what resilience actually means for the grid and to understand how each grid operator addresses the issue.

Wyoming Land Quality Division Self-Bonding Rules. On August 20, 2018, the Wyoming Land Quality Division, through the Land Quality Advisory Board, offered for public comment proposed changes to self-bonding rules related to reclamation obligations. The proposal included requiring that the self-bonding guarantor be the ultimate parent company and that the maximum amount of bonding be limited to 75% of the company's calculated bond amount. Additionally, the proposal required the self-bonding party to be of investment grade quality using ratings issued by nationally recognized credit rating services, such as Moody's Investor Service or Standard and Poor's Corporation. This requirement would replace the current qualifying tests using a bonding party's audited financial statements. The proposed rule was approved by the Wyoming Land Quality Advisory Board on September 19, 2018, and the Environmental Quality Counsel on February 19, 2019. It was signed by the governor of Wyoming on May 3, 2019. The Company currently meets all its bonding obligations in Wyoming through the use of commercial surety bonds. Under the new rules, the Company does not qualify for self-bonding based on its current credit rating.

Federal Report on Climate Change. On November 23, 2018, the U.S. Global Change Research Program, a working group comprised of 13 U.S. governmental departments and agencies, issued the Fourth National Climate Assessment. The report lists the observed effects of “increasing greenhouse gas concentrations on Earth’s climate” and enumerates the impacts of those observed effects. The report also discusses the alternatives for reducing the impacts of climate-related risks, including through mitigation and adaptation. While there are no explicit regulatory actions that flow from the issuance of the report, both the legislative and executive branches of government may rely on its conclusions to shape and justify policies and actions going forward.

Regulatory Matters — Australia

The Australian mining industry is regulated by Australian federal, state and local governments with respect to environmental issues such as land reclamation, water quality, air quality, dust control, noise, planning issues (such as approvals to expand existing mines or to develop new mines) and health and safety issues. The Australian federal government retains control over the level of foreign investment and export approvals. Industrial relations are regulated under both federal and state laws. Australian state governments also require coal companies to post deposits or give other security against land which is being used for mining, with those deposits being returned or security released after satisfactory reclamation is completed.

Native Title and Cultural Heritage. Since 1992, the Australian courts have recognized that native title to lands and water, 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 mining activities 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.

In February 2019, the New South Wales (NSW) Land and Environment Court (LEC) upheld the government’s denial of a planning approval for a non-Peabody coal mining project (*Gloucester Resources Limited v. Minister for Planning*). Although the approval was refused for other reasons, the judge in that case discussed ‘Scope 3’ greenhouse gas emissions resulting from the consumption of coal to be mined under the proposed project. Such emissions are often raised as a ground of objection to Australian mining projects, including our mining projects. For example, in a subsequent LEC decision (*Australian Coal Alliance Incorporated v. Wyong Coal Pty Ltd*), the approval of a coal mining project was confirmed after such emissions had been considered by the relevant authority. In August 2019, Peabody and Glencore received approval from the NSW Independent Planning Commission (IPC) for the United Wambo project, subject to conditions (Export Conditions) requiring the joint venture to prepare an Export Management Plan setting out protocols for using all reasonable and feasible measures to ensure that any coal extracted from the mine that is to be exported from Australia is only exported to countries that are parties to the Paris Agreement (as defined below) or countries that the NSW Planning Secretary considers to have similar policies for reducing greenhouse gas emissions. In September 2019, the IPC declined to approve a non-Peabody ‘greenfield’ coal mining project (Bylong) for various reasons, including Scope 3 greenhouse gas emissions.The applicant for that project has applied for the IPC’s decision to be judicially reviewed. The IPC subsequently approved another non-Peabody coal mining project (Rix’s Creek) without any Export Conditions. In October 2019, the NSW government introduced into Parliament proposed amendments to legislation and policy that would, if passed, have the effect of invalidating Export Conditions imposed on future NSW planning approvals, as well as no longer requiring consent authorities to consider ‘downstream emissions’ when assessing developments for the purposes of mining, petroleum production or extractive industry. The NSW government has announced changes to the IPC and planning system process which aims to improve timeframes and efficiencies for project approvals and providing more clarity on the IPC’s role in determining applications including seeking guidance on government policy.

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 2008, Planning Act 2016, Coal Mining Safety and Health Act 1999, Minerals and Energy Resources (Common Provisions) Act 2014, 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, Biosecurity Act 2014, 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. 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 that 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, which became 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 that provides more certainty to the industry on the circumstances in which 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, Coal Mine Subsidence Compensation Act 2017, Environmental Planning and Assessment Act 1979 (EPA 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, Biodiversity Conservation Act 2016 (BC Act), Heritage Act 1977, Aboriginal Land Rights Act 1983, Crown Land Management Act 2016, Dangerous Goods (Road and Rail Transport) Act 2008, Fisheries Management Act 1994, Forestry Act 2012, Native Title (New South Wales) Act 1994, Biosecurity Act 2015, Roads Act 1993 and National Parks & Wildlife Act 1974.

Under the EPA Act, environmental planning instruments must be considered when approving a mining project development application. Decision makers review 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” consideration contained in the relevant legislation. Effective from March 1, 2018, the EPA Act was amended to introduce a number of changes to planning laws in New South Wales. The EPA Act was further amended in June 2018 to revoke a process for modifying development approvals under the former Section 75W of the EPA Act. As a result, new development approvals will need to be obtained unless the proposed project will be substantially the same development as it was when the development approval was last modified under Section 75W, in which case the existing development approval can be modified. If a new development approval is required then this could take additional time to achieve.

On August 25, 2017, the BC Act commenced in New South Wales and imposes a revised framework for the assessment of potential impacts on biodiversity that may be caused by a development, such as a proposed mining project. The BC Act requires these potential impacts on biodiversity to be offset in perpetuity, by one or more of the following means: securing land based offsets and retiring biodiversity credits, making a payment into a biodiversity conservation fund or in some cases through mine site ecological rehabilitation. The data collected from the biodiversity impact assessment process is inputted into a new offsets payment calculator in order to determine the amount payable by the proponent to offset the impacts. The proposed development can only proceed once the biodiversity offset obligations have been satisfied.

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 provide financial assurance to the relevant authorities which is calculated in accordance with current regulatory requirements. This financial assurance is in the form of cash, surety bonds or bank guarantees which are supported by a combination of cash collateral, deeds of indemnity and guarantee and letters of credit issued under our credit facility and accounts receivable securitization program. We operate in both the Queensland and New South Wales state jurisdictions.

Our reclamation bonding requirements in Australia were $243.9 million as of December 31, 2019. The bond requirements represent the calculated cost to reclaim the current operations of a mine if it ceases 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 $224.4 million as of December 31, 2019. 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 projected to be a number of years 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 Planning and Environment and the New South Wales Resources Regulator, and authorizes the holder of a mining tenement to extract a mineral subject to obtaining consent under the EPA Act 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 the extent of disturbance during the MOP period.

Queensland Reclamation. The EP Act is administered by the Department of Environment and Science, 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. All mining operations must be carried out in a manner so as to ensure compliance with the conditions in the EA. The mines submit an annual return reporting on their EA compliance.

In November 2018, the Queensland government passed the Mineral and Energy Resources (Financial Provisioning) Act 2018 providing for a new financial assurance (FA) framework and new progressive rehabilitation requirements. The new FA framework creates a pooled fund covering most mines and most of the total industry liability, plus other options for providing FA if not part of the pooled fund (for example, allowing insurance bonds or cash). The percentage rate of the total rehabilitation cost payable into the pooled fund will take into account the financial strength of the holder of the EA for the mine and the project strength of the mine. The total rehabilitation cost is determined using an updated rehabilitation cost calculator, which no longer provides for discounting. The commencement date for the new FA framework was April 1, 2019 and there is a transitional period during which we will move each of our mines in Queensland into the new FA framework.

The new progressive rehabilitation requirements commenced on November 1, 2019 and require each mine, within a three-year transitional period, to establish a schedule of rehabilitation milestones covering the life of the mine, and any significant changes to the timing of rehabilitation will require regulatory approval. If there is to remain an area within the mine that does not have a post-mining land use (referred to as a non-use management area or NUMA) then each such NUMA will need to pass a public interest evaluation test as part of the approval process. An example of a NUMA is the void that remains after open-cut mining activities have been completed. Under the legislation, each current mine is exempt from the requirement to justify its NUMAs to the extent that its current approvals provide for such areas. We are of the view that there will not be a need to seek any further regulatory approvals for any of the NUMAs at any of our Queensland mines.

Residual Risks. On November 19, 2018, the Queensland government released for public consultation a discussion paper on managing 'residual risks' of mining activities. On completion of all mining activities, the holder of the EA for the mine can apply to surrender the EA once all conditions, requirements and rehabilitation obligations have been met. When approving the surrender, the government can request a residual risk payment from the holder of the EA for the mine to cover potential rehabilitation or maintenance costs incurred after the surrender has been accepted. The discussion paper contemplates two approaches for determining residual risk payments. Depending on the level of risk of a particular site, a cost calculator tool might be used or a panel of appropriately qualified experts might undertake a qualitative and quantitative risk assessment. Industry and the Company continue to consult with the government on the proposed residual risk payment regime.

Federal Reclamation. In February 2017, the Australian Senate established a Committee of Inquiry into the rehabilitation of mining and resources projects as it relates to Commonwealth responsibilities, for example, under the Environment Protection and Biodiversity Conservation Act 1999. The Committee released their report in March 2019. The Committee was unable to reach unanimous agreement on a set of recommendations. It is unclear the extent to which the report will impact policy reform at a federal government level.

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.

Beginning in 2015, a small number of coal mine workers in Queensland and New South Wales were diagnosed with coal workers' pneumoconiosis (CWP, also known as black lung) following decades of assumed eradication of the disease. The Queensland government held a Parliamentary inquiry into the re-emergence of CWP in the state, which included public hearings with appearances by representatives of the coal mining industry, coal mine workers, the regulator and others. The Queensland Parliamentary Committee conducting the inquiry issued its final report on May 29, 2017. In finding that it is highly unlikely CWP was ever eradicated in Queensland, the Committee made 68 recommendations to ensure the safety and health of coal mine workers. These include an immediate reduction to the occupational exposure limit for respirable coal dust equivalent to 1.5mg/m^3 for coal dust and 0.05 mg/m^3 for silica and the establishment of a new and independent Mine Safety Authority to be funded by a dedicated proportion of coal and mineral royalties and overseeing the Mines Safety Inspectorate. 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.

Safe Work Australia (SWA) is currently reviewing the Workplace Exposure Standards (WES) for all airborne contaminants including welding fumes and diesel particulate matter and giving priority to the WES for coal dust and silica. The review is expected to continue until June 2020. SWA's draft evaluation reports will include recommendations for exposure limits. The exposure limits recommended by SWA are based on toxicological information and other monitoring data. SWA have recommended exposure limits of 1.5mg/m^3 for coal dust and 0.05 mg/m^3 for silica.

Since August 2017, the Workers' Compensation and Rehabilitation Act 2003 provides for a medical examination process for retired or former coal workers with suspected CWP and an additional lump sum compensation for workers with CWP, and additionally clarifies that a worker with CWP can access further workers' compensation entitlements if they experience disease progression.

In October 2018 the Queensland government passed the Mines Legislation (Resources Safety) Amendment Act 2018, which introduces significant changes to the Coal Mining Safety and Health Act 1999 concerning, among other things, duties of officers, reporting requirements for coal mine worker diseases, reporting defects and hazards affecting plant and substances, contractor and service provider safety and health management plans, new powers to suspend or cancel an individual's statutory certificate of competency and increasing penalties and inspector powers.

Following the re-identification of coal workers' pneumoconiosis and six mining and quarrying fatalities that occurred over a 12-month period, the Resources Safety and Health Queensland Bill 2019 was introduced into Queensland Parliament in September 2019. The bill establishes Resources Safety and Health Queensland (RSHQ) as a statutory body designed to ensure independence of the mining safety and health regulator. RSHQ will include inspectorates for coal mines, mineral mines and quarries, explosives and petroleum and gas. The bill seeks to enhance the role of advisory committees to identify, quantify and prioritize safety and health issues in the mining and quarrying industries. It also provides for an independent Work Health and Safety Prosecutor to prosecute serious offences under resources safety legislation.

In February 2020, the Queensland government has introduced into Parliament legislation which will introduce the criminal offense of 'industrial manslaughter' for executive officers, individuals who are "senior officers" and companies in the mining industry. Individuals would face a maximum prison sentence of 20 years and companies could be fined up to approximately $13 million Australian dollars. The legislation has also introduced the requirement for statutory role holders to be employees of the coal mine operator entity with a 12-month transition period. The bill is currently under review by a Parliamentary Committee.

Industrial Relations. A national industrial relations system, the Fair Work Act and National Employment Standards, administered by the federal government applies to all employers and employees. The matters regulated under the national system include general employment conditions, unfair dismissal, enterprise bargaining, bullying claims, industrial action and resolution of workplace disputes. Most of the hourly workers employed in our mines are also covered by the Black Coal Mining Industry Award and company specific enterprise agreements approved under the national system.

National Greenhouse and Energy Reporting Act 2007 (NGER Act). 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 as part of a single, national reporting system. The Clean Energy Regulator administers the NGER Act. The federal Department of Environment and Energy is responsible for NGER Act-related policy developments and review.

On July 1, 2016, amendments to the NGER Act implemented the Emissions 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 at or below the baseline or face penalties.

The National Greenhouse and Energy Reporting Rule 2015 outlines key elements of a responsible emitter's duty to avoid an excess emissions situation and provides detail on how it can meet that requirement. The rule was amended in March 2019 with the effect that all current reported covered emissions baselines will expire on June 30, 2020, and there will be alternatives for setting new baselines, including by reference to default emissions intensity values.

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 15.0% on pricing over $150 Australian dollars per tonne. The rate is 7.0% 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.

Sydney Water Catchment Areas. In November 2017, the New South Wales government established an independent expert panel (Panel) to advise the Department of Planning, Industry and Environment (DPIE) on the impact of underground mining activities in Sydney's water catchment areas, including at our Metropolitan Mine. The Panel issued an initial report to DPIE in November 2018, which was publicly released in December 2018 and only concerned mining activities at two mines, our Metropolitan Mine and a competitor's Dendrobium Mine. After consultation with stakeholders, including Peabody, a final report was released in October 2019. The final report updates and finalizes the initial report and also makes findings and recommendations concerning mining activities and effects across the catchment as a whole.

The Panel's reports acknowledge the major effort at the Metropolitan and Dendrobium Mines over the last decade to employ best practice modeling and assessment methods undertaken by suitable specialists, with expert peer review while recommending continued rigorous monitoring and impact assessment in order to build on the knowledge base regarding mining-induced subsidence and its impacts on groundwater and surface water. The reports endorse the government taking an incremental approach to mining approvals that provides for considering existing and emerging information and knowledge gaps. The Panel concluded in the final report that the average daily water inflow over the last three years at the Metropolitan Mine is generally less than 0.2 megaliters per day and shows no evidence of connected fracture regime to surface or correlation with rainfall. It also concluded that the potential for water to be diverted out of Woronora Reservoir and into other catchments through valley closure shear planes and geological structures will require careful assessment in the future because it is planned that most of the remaining longwall panels in the approved mining area will pass beneath the reservoir. A range of matters remain to be considered by the Panel, including the cumulative impacts of flow losses and the relative significance of these for water supplies as well as the practicalities associated with establishing a robust regional water balance model.

The DPIE will now consider the recommendations in the Panel's final report and has said that in the meantime no new development applications for mining in the catchment will be determined. We do not currently have any such applications awaiting determination. The latest extraction plans for the Metropolitan Mine are progressing on an incremental basis and we continue to conduct robust monitoring, data collection and reporting and have been actively consulting with the government on Metropolitan's approval processes and mine design to ensure that operational impacts are appropriately managed and minimized as far as possible.

Global Climate

In the U.S., Congress has considered legislation addressing global climate issues and greenhouse gas emissions, but to date, no such legislation has been signed into law. 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 CAA. 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.” In particular, in 2015, the EPA announced final rules (known as the CPP) for regulating carbon dioxide emissions from existing and new fossil fuel-fired EGUs. Twenty-seven states and governmental entities, as well as utilities, industry groups, trade associations, coal companies (including Peabody), and other entities, challenged the CPP in federal court. Implementation of the CPP was stayed by the U.S. Supreme Court pending resolution of its legal challenges. In October 2017, the EPA proposed to change its legal interpretation of section 111(d) of the CAA, the authority that the agency relied on for the original CPP. The EPA relied on the proposed reinterpretation until August 2018, when it proposed the Affordable Clean Energy Rule (the ACE Rule) to replace the CPP with a system where states would develop emissions reduction plans using BSER measures (essentially efficiency heat rate improvements), and the EPA would approve the state plans if they use EPA-approved candidate technologies. Changes in the NSR program were also proposed to allow efficiency improvements to be made without triggering NSR requirements. In September 2019, the ACE Rule, which provides states with the flexibility to regulate on a plant-by-plant basis with a focus on coal-fired EGUs, became effective and the CPP was repealed. Proposed revisions to the regulations under the NSR program that were part of the ACE proposal were separated and the EPA indicated that it intends to take final action on the proposed NSR program reforms at a later date. Following the effectiveness of the ACE Rule, the case challenging the CPP in federal court was dismissed as being moot. The ACE Rule is being challenged in the D.C. Circuit Court of Appeals and its ultimate impact will depend on state implementation plan requirements and the outcome of associated legal challenges.

At the same time, 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.

Several other U.S. 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.

We participated in the Department of Energy’s Voluntary Reporting of Greenhouse Gases Program until its suspension in May 2011, and we regularly disclose in our annual Environmental, Social and Governance 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. Other banks (such as BNP Paribas and HSBC) have pledged to end financing of certain fossil fuel projects and companies. Some insurance companies (such as Zurich and Swiss Re) have announced that they will no longer insure coal operations and companies. And some large investors (including Lloyd’s of London) have announced that they plan to divest coal stocks from their investment holdings.

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 Paris Agreement). The agreement was entered into force on November 4, 2016 after ratification and execution by more than 55 countries, including Australia, that account for at least 55% of global greenhouse gas emissions. The U.S. has begun the process of withdrawing from the Paris Agreement, which cannot be completed until 2020 under the terms of the agreement.

In October 2017, the Australian Federal Government released a plan aimed at delivering an affordable and reliable energy system that meets Australia's international commitments to emissions reduction. The plan was referred to as the National Energy Guarantee (NEG) and was aimed at changing the National Electricity Market and associated legislative framework. The NEG was abandoned by the Australian government in September 2018. Following the outcome of the federal election in May 2019, the federal government confirmed it will not revive the former NEG policy. Instead, the government will pursue a new energy and climate change policy, which includes a $2 billion Australian dollars investment in projects to bring down Australia's greenhouse gas emissions. The Climate Solutions Fund is an extension of the former Emissions Reduction Fund. The government has confirmed that it remains committed to meeting Australia's Paris Agreement targets but that the focus of energy policy will be on driving down electricity prices.

The enactment of future laws or the passage of regulations regarding emissions from the use 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 such 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 development and deployment of CCUS technologies as well as acceptance of CCUS technologies to meet regulations and the alternative uses for coal. Higher-efficiency coal-fired power plants may also be an option for meeting laws or regulations related to emissions from coal use. Several countries, including major coal users such as China, India and Japan, included using higher-efficiency coal-fueled power plants in their plans under the Paris Agreement. 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 which sometimes show that if implemented in the manner assumed by the analyses, the potential laws, regulations and policies could result in material adverse impacts on our operations, financial condition or cash flow. We do not believe that such analyses reasonably predict the quantitative impact that future laws, regulations or other policies may have on our results of operations, financial condition or cash flows.

Available Information

We file or furnish annual, quarterly and current reports (including any exhibits or amendments to those reports), proxy statements and other information with the SEC. These materials are available free of charge through our website (www.peabodyenergy.com) as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information included on our website does not constitute part of this document. These materials may also be accessed through the SEC's website (www.sec.gov).

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

Item 1A. *Risk Factors.*

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

Risks Associated with Our Emergence from the Chapter 11 Cases

As a result of our emergence from our Chapter 11 Cases, our historical financial information is not indicative of our future financial performance.

Our capital structure was significantly altered through the implementation of our Plan. As a result, we are subject to the fresh start reporting rules required under the Financial Accounting Standards Board ASC Topic 852, Reorganizations. Under applicable fresh start reporting rules, our assets and liabilities were adjusted to fair values and our accumulated deficit was restated to zero. Accordingly, our consolidated financial condition and results of operations from and after April 2, 2017 are not directly comparable to the financial condition or results of operations reflected in our consolidated historical financial statements.

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 has previously experienced strong headwinds. Current pricing levels of both seaborne and domestic coal products may not be sustainable in the future. If coal prices decrease 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 and capacity utilization of electricity generating units (whether coal or non-coal);
- changes in the fuel consumption and dispatch patterns of electric power generators, whether based on economic or non-economic factors;
- the proximity, capacity and cost of transportation and terminal facilities;
- the relative price of natural gas and other energy sources used to generate electricity;
- competition with and the availability, quality and price of coal and alternative fuels, including natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power;
- the strength of the global economy;
- the global supply and production costs of thermal and metallurgical coal;
- the demand for steel, which may lead to price fluctuations in the monthly and quarterly repricing of our metallurgical coal contracts;
- weather patterns, severe weather and natural disasters;
- governmental regulations and taxes, including tariffs or other trade restrictions as well as 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.

For U.S. thermal coal, 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. For seaborne coal, we negotiate pricing for metallurgical coal contracts on a quarterly, spot or index basis and seaborne thermal coal contracts on an annual, spot or index basis.

Thermal coal accounted for the majority of our coal sales by volume during 2019 and 2018. 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 multiple fuels, including coal; (iv) 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-fueled generation units) as current and potentially increasing regulatory costs and other factors impact the operating decisions of electric power generators. In addition, some electric power generators are making uneconomic decisions to close coal-fueled generation units given ongoing pressure to shift away from coal generation. Many of the new power plants in the U.S. may be fueled by natural gas because gas-fired plants have been less expensive to construct, permits to construct these plants are easier to obtain based on emissions profiles, and electric power generators may face public and governmental pressure to generate a larger portion of their electricity from natural gas-fueled units and alternative energy sources. Increasingly stringent regulations along with stagnant 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 22% and 28% of our revenues in 2019 and 2018, respectively. Changes in governmental policies and regulations and changes in the steel industry, including the demand for steel, could reduce the demand for our metallurgical coal. Lower demand for metallurgical coal in international markets could 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.

The balance between coal demand and supply, 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. In the U.S., we compete with other fuel sources used for electricity generation, such as natural gas and renewables. Our seaborne products compete with other producers as well as other fuel sources. 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 low prices for other fuels may also cause utilities to phase out or close existing coal-fueled power plants or reduce construction of new coal-fueled power plants. In the United States, no new coal-fueled power plants are being constructed or reopened after closure. These closures 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, or if the pricing, volumes or other elements of those agreements materially adjust, 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, price indices 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 may experience reductions 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. Some coal supply agreements allow customers to vary the volumes of coal that they are required to purchase during a particular period, and where coal supply agreements do not explicitly allow such variation, customers sometimes request that we amend the agreements to allow for such variation. 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, volatile matter, coking properties, 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, 2019, we derived 33% of our total revenues from our five largest customers. Those five customers were supplied primarily from 43 coal supply agreements (excluding trading transactions) expiring at various times from 2020 to 2025. 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.

One of our five largest customers, the Navajo Generating Station, was exclusively served by our Kayenta Mine, included in our Western U.S. Mining operations, that had no other customers. During the third quarter of 2019, the Kayenta Mine shipped its final tons. The mine's approximate Adjusted EBITDA contribution, approximate depreciation, depletion and amortization and asset retirement obligation expense, and tons of coal sold are presented in the table below for the respective periods. Depreciation, depletion and amortization and asset retirement obligation expense for the Successor periods are not comparable to those of the Predecessor periods due to the revaluation of the Company's property, plant, equipment, and mine development to fair value in connection with fresh start reporting.

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars and tons in millions)			
Adjusted EBITDA	$ 170	$ 110	$ 77	$ 27
Depreciation, depletion and amortization and asset retirement obligation expense	$ 111	$ 120	$ 60	$ 19
Tons of coal sold	4.0	6.6	4.8	1.5

Our trading and hedging activities do not cover certain risks and may expose us to earnings volatility and other risks.

We historically entered into hedging arrangements designed primarily to manage price volatility of the Australian dollar, coal and diesel fuel. Currently, we primarily enter into derivative financial instruments, including financial swaps and options, designed to manage coal price volatility and increases in the Australian dollar exchange rate. We are currently subject to price volatility on diesel fuel utilized in our mining operations. We may in the future enter into hedging arrangements to manage this price risk, or other exposures.

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, which 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.

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. A global economic recession and/or a worldwide financial and credit market disruption could have a negative impact on us and on the coal industry generally. If any of these conditions occur, if coal prices recede to or below levels experienced in 2015 and early 2016 for a prolonged period or if there are 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, would 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.

Risks inherent to mining could increase the cost of operating our business, and events and conditions that could occur during the course of our mining operations could have a material adverse impact on us.

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:

- elevated gas levels;
- fires and explosions, including from methane gas or coal dust;
- accidental mine water discharges;
- weather, flooding and natural disasters;
- hazardous events such as roof falls and high wall or tailings dam failures;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- key equipment failures;
- variations in coal seam thickness, coal quality, the amount of rock and soil overlying coal deposits, and geologic conditions impacting mine sequencing;
- delays in moving our longwall equipment;
- unexpected maintenance problems; and
- unforeseen delays in implementation of mining technologies that are new to our operations.

We maintain insurance policies that provide limited coverage for some of the risks referenced above, and those insurance policies may lessen the impact associated with these risks. However, there can be no assurance as to the amount or timing of recovery under our insurance policies in connection with losses associated with these risks.

Our North Goonyella Mine in Queensland, Australia experienced a fire in a portion of the mine during September 2018 and mining operations have been suspended since then. During the first quarter of 2019, we completed segmenting of the mine into multiple zones to facilitate a phased reventilation and re-entry of the mine. We commenced reventilation of the first zone of the mine during the second quarter of 2019 and subsequently re-entered the area in the third quarter. Following these activities and a detailed review and assessment of North Goonyella, we determined that due to the time, cost and required regulatory approach to ventilate and re-enter the rest of the mine, we will not pursue attempts to access certain portion of the mine through existing mine workings, but instead will move to the southern panels. We are currently in discussions with the Queensland Mines Inspectorate (QMI) regarding ventilation and re-entry of the second zone of the current mine configuration. Based on the planned approach, we expect no meaningful production from North Goonyella for three or more years. In 2020, we are commencing a commercial process for North Goonyella in conjunction with the existing mine development. The process comes in response to expressions of interest from potential strategic partners and other producers. Commercial outcomes could include a strategic financial partner, joint venture structure or complete sale of North Goonyella. Based on the success of discussions with QMI and/or progression of the commercial process being launched, we will determine the appropriate level, if any, and timing of capital expenditures. If after exploring all reasonable mine-planning steps focused on resuming mining activities at the North Goonyella Mine and other commercial outcomes, we determine that we are unable to extract coal from the southern panels of the mine, our results of operations, financial condition and cash flows could be materially and adversely impacted. In addition, the costs that may be incurred to return the mine to active operations (if the mine returns to active operations) are uncertain and could be significant. Refer to Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information regarding our North Goonyella Mine.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal may be diminished.

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 $1.1 billion, with terms ranging up to 23 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.

We have contract-based intangible liabilities primarily consisting of unutilized capacity under port and rail take-or-pay contracts. Future unutilized capacity and the amortization periods related to the take-or-pay contract intangible liabilities are based upon estimates of forecasted usage. We anticipate that the amortization of the intangible liability, which is classified as a reduction to “Operating costs and expenses,” will extend through 2043.

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. 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 have from time to time been 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. During the year ended December 31, 2019, the Company recorded $270.2 million of impairment charges related to such factors, as further described in Note 5. “Asset Impairment” to the accompanying consolidated financial statements. These factors may trigger the recognition of additional impairment charges in the future, which could have a substantial impact on our results of operations.

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 adjustments to the carrying value of our assets.

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, 2019, we had approximately 6,600 employees (excluding employees that were employed at operations classified as discontinued), which included approximately 5,000 hourly employees. We are party to labor agreements with various labor unions that represent certain of our employees. Such labor agreements are negotiated periodically, and, therefore, we are subject to the risk that these agreements may not be able to be renewed on reasonably satisfactory terms. Approximately 42% of our hourly employees were represented by organized labor unions and generated approximately 19% of our coal production for the year ended December 31, 2019. 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 or successfully negotiate contracts with our employees who are represented by unions, we could potentially experience labor disputes, strikes, work stoppages, slowdowns or other disruptions in production that could negatively impact our profitability.

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 provide a third-party surety bond or provide a letter of credit. As of December 31, 2019, we had $1,609.2 million of outstanding surety bonds and $200.5 million of letters of credit with third parties in order to provide required financial assurances for post-mining reclamation, workers’ compensation and other insurance obligations, coal lease-related and other obligations and performance guarantees.

Our financial assurance obligations may increase or become more costly due to a number of factors, and surety bonds and letters of credit may not be available to us, particularly in light of some banks and insurance companies' announced unwillingness to support fossil fuel companies. Alternative forms of financial assurance such as self-bonding may be further restricted or terminated where currently available. 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, bank guarantees or letters of credit; and
- inability to provide or fund collateral for current and future third-party issuers of surety bonds, bank guarantees or letters of credit.

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:

- workplace 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, regulations or orders 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, regulations and approvals), including proposals related to the protection of the environment or the reduction of greenhouse gas emissions that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. Some of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser's plant or results in specified increases in the cost of coal or its use. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

For additional information 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 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, renew or maintain permits necessary for our operations, or we may be unable to obtain, renew or maintain such permits without conditions on the manner in which we run 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, change frequently 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) and otherwise engage in the permitting process, including bringing citizens' lawsuits to challenge the issuance of permits, the validity of environmental impact statements or the performance of mining activities. 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 any related opposition may be extensive and time-consuming and may delay commencement or continuation of exploration or production which would 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 flows and profitability.

The Corps regulates certain activities affecting navigable waters and waters of the U.S., including wetlands. Section 404 of the 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 as well as 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 SMCRA, the National Pollution Discharge Elimination System permit process and various other environmental programs. Potential future laws, regulations and policies could result in material adverse impacts on our operations, financial condition or cash flows, in view of the significant uncertainty surrounding each of these potential future laws, regulations and policies.

Our mining operations are subject to extensive forms of taxation, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal competitively.

Federal, state, provincial or local governmental authorities in nearly all countries across the global coal mining industry impose various forms of taxation, including production taxes, sales-related taxes, royalties, environmental taxes, mining profits taxes and income taxes. If new legislation or regulations related to various forms of coal taxation, which increase our costs or limit our ability to compete in the areas in which we sell our coal, are adopted, our business, financial condition or results of operations could be adversely affected.

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

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

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, 2019, we leased a total of 47,272 acres from the federal government subject to those limitations.

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 or secure 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.

We face numerous uncertainties in estimating our economically recoverable coal reserves and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

Coal is economically recoverable when the price at which our coal can be sold exceeds the costs and expenses of mining and selling the coal. The costs and expenses of mining and selling the coal are determined on a mine-by-mine basis, and as a result, the price at which our coal is economically recoverable varies based on the mine. Forecasts of our future performance are based on, among other things, estimates of our recoverable coal reserves. We base our reserve information on engineering, economic and geological data assembled and analyzed by our staff and third parties, which includes various engineers and geologists. The reserve estimates as to both quantity and quality are updated from time to time to reflect production of coal from the reserves and new drilling or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of coal and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves necessarily depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions include:

- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experience in areas we currently mine;
- demand for coal;
- current and future market prices for coal, contractual arrangements, operating costs and capital expenditures;
- severance and excise taxes, royalties and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies;
- the ability to obtain, maintain and renew all required permits;
- employee health and safety; and
- historical production from the area compared with production from other producing areas.

As a result, actual coal tonnage recovered from identified reserve areas or properties and revenues and expenditures with respect to our reserves may vary materially from estimates. Thus, these estimates may not accurately reflect our actual reserves. Any material inaccuracy in our estimates related to our reserves could result in lower than expected revenues, higher than expected costs or decreased profitability which could materially and adversely affect our business, results of operations, financial position and cash flows.

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

Our international platform increases our exposure to country risks, 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, political and sovereign 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 flows could be adversely affected by these activities.

Our proposed joint venture with Arch may not be completed.

On June 18, 2019, we entered into a definitive implementation agreement with Arch to establish a joint venture that will combine the respective Powder River Basin and Colorado mining operations of Peabody and Arch.

The closing of our proposed joint venture with Arch is subject to various conditions to closing, including the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, the receipt of certain other required regulatory approvals and the absence of injunctions or other legal restraints preventing the formation of the joint venture. These closing conditions may not be satisfied, and in that circumstance we may be unable or unwilling to complete this joint venture. If the closing has not occurred on or prior to June 18, 2020 and all required regulatory approvals have not been obtained, the Implementation Agreement may be terminated by either Peabody or Arch no later than June 29, 2020 following written notice and the payment by the terminating party to the non-terminating party of a termination fee of $40 million; provided, however, that the non-terminating party may elect to extend the Implementation Agreement until September 18, 2020. If the non-terminating party exercises this option to extend, the termination fee payable to the non-terminating party by the terminating party if the closing does not occur on or prior to September 18, 2020 will be reduced to $25 million.

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 safety results, operating costs and productivity and adversely impact our results of operations and reputation.

The benefits that are expected to result from the proposed joint venture with Arch will depend, in part, on our ability to realize the anticipated cost synergies in the transaction, our and Arch's ability to successfully integrate our Powder River Basin and Colorado mining operations, and our and Arch's ability to successfully manage the joint venture on a going-forward basis. It is not certain that we will realize these benefits at all, and if we do, it is not certain how long it will take to achieve these benefits. If, for example, we are unable to achieve the anticipated cost savings, or if there are unforeseen integration costs, or if we and Arch are unable to operate the joint venture smoothly in the future, the financial performance of the joint venture may be negatively affected.

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 modify our portfolio of operations and/or 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 employees, our customers or other third-parties.

We use digital technology to conduct our business operations and engage with our customers, vendors, employees, financial institutions and other partners. Our business depends on the reliable and secure operation of computer systems, network infrastructure, digital communication technologies and other information technology. Problems may arise in both our internally managed systems and those of 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 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 $625.7 million as of December 31, 2019, of which $32.3 million was classified as a current liability.

These liabilities are actuarially determined. We use various actuarial assumptions, including the discount rate, future cost trends, mortality tables 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. We develop our actuarial determinations of liabilities using actuarial mortality tables we believe best fit our population's actual results. In deciding which mortality tables to use, we periodically review our population's actual mortality experience and evaluate results against our current assumptions as well as consider recent mortality tables published by the Society of Actuaries Retirement Plans Experience Committee in order to select mortality tables for use in our year end valuations. If our mortality tables do not anticipate our population's mortality experience as accurately as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. 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 impacts of coal combustion on global climate are increasingly leading to consequences that have affected and could continue to affect demand for our products or our securities and our ability to produce, including increased governmental regulation of coal combustion and unfavorable investment decisions by electricity generators.

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 greenhouse gases, including emissions of carbon dioxide from coal combustion by power plants.

The enactment of future laws or the passage of regulations regarding emissions from the use 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 mines or coal-fueled power stations could adversely impact the global supply and demand for coal. The potential financial impact on us of such 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 development and deployment of CCUS technologies as well as acceptance of CCUS technologies to meet regulations and the alternative uses for coal. Similarly, higher-efficiency coal-fired power plants may also be an option for meeting laws or regulations related to emissions from coal use. Several countries, including some major coal users such as China, India and Japan, included using higher-efficiency coal-fueled power plants in their plans under the Paris Agreement. 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, which sometimes show that if implemented in the manner assumed by the analyses, the potential laws, regulations and policies could result in material adverse impacts on our operations, financial condition or cash flows. 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.

Numerous activist groups are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal, and potentially materially and adversely impacting our future financial results, liquidity and growth prospects.

Several non-governmental organizations have undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation in the U.S. and across the globe. In an effort to stop or delay coal mining activities, activist groups have brought lawsuits challenging the issuance of individual coal leases, and challenging the federal coal leasing program more broadly. Other lawsuits challenge historical and pending regulatory approvals, permits and processes that are necessary to conduct coal mining operations or to operate coal-fueled power plants, including so-called “sue and settle” lawsuits where regulatory authorities in the past have reached private agreements with environmental activists that often involve additional regulatory restrictions or processes being implemented without formal rulemaking.

The effect of these and other similar developments has been to make it more costly and difficult to maintain our business. These cost increases and/or a substantial or extended decline in the prices we receive for our coal due to these or other factors could reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and could result in losses.

Risks Related to Our Indebtedness and Capital Structure

Our financial performance could be adversely affected by our indebtedness.

As of December 31, 2019, we had approximately $1.3 billion of indebtedness outstanding, excluding finance leases and debt issuance costs.

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;
- increasing our vulnerability to general adverse economic and industry or regulatory 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 indebtedness subjects 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. The terms of our indebtedness 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.

A downgrade in our credit ratings or other unfavorable indicators could result in, among other matters, additional required financial assurances related to our reclamation bonding requirements, a requirement to post additional collateral on derivative trading instruments that 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.

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. Our indebtedness may restrict the use of the proceeds from any such sales. We may not be able to complete those sales and the proceeds may not be adequate to meet any debt service obligations then due.

Despite our indebtedness, we may still be able to incur substantially more debt, including secured debt, which could further increase the risks associated with our indebtedness.

We may be able to incur substantial additional indebtedness in the future, including additional secured debt. Although covenants under the indenture governing our senior secured notes and the agreements governing our other indebtedness, including our credit facility, revolver and finance leases 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 senior secured notes and the agreements governing our other indebtedness do not limit us from incurring obligations that do not constitute indebtedness as defined therein.

The terms of our indenture governing our senior secured notes and the agreements and instruments governing our other indebtedness impose restrictions that may limit our operating and financial flexibility.

The indenture governing our senior secured notes and the agreements governing our other indebtedness contain certain restrictions and covenants which restrict our ability to incur liens and/or debt or provide guarantees in respect of obligations of any other person and other restrictions, all of 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. Our credit facility also contains a mandatory prepayment provision providing that certain amounts of excess cash flow (as defined in the agreements governing the facility) must be utilized to make payments on the outstanding balance under that facility.

These covenants limit, 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.

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 our senior secured notes. If any such default occurs, subject to applicable grace periods, the holder of our senior secured notes may elect to declare all outstanding senior secured notes, together with accrued interest and other amounts payable thereunder, to be immediately due and payable. If the obligations under our 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 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 senior secured notes and a cross-default to certain of our other indebtedness 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.

The number and quantity of viable financing alternatives available to us may be significantly impacted by unfavorable lending and investment policies by financial institutions and insurance companies associated with concerns about environmental impacts of coal combustion, and negative views around our efforts with respect to environmental and social matters and related governance considerations could harm the perception of our company by certain investors or result in the exclusion of our securities from consideration by those investors.

Global climate issues, including with respect to greenhouse gases such as carbon dioxide and methane and the relationship that greenhouse gases have with climate change, continue to attract significant public and scientific attention.

Certain banks, other financing sources and insurance companies have taken actions to limit available financing and insurance coverage for the development of new coal-fueled power plants and coal producers and utilities that derive a majority of their revenue from thermal coal, which also may adversely impact the future global demand for coal. Increasingly, the actions of such financial institutions and insurance companies are informed by non-standardized “sustainability” scores, ratings and benchmarking studies provided by various organizations that assess corporate governance related to environmental and social matters. Further, there have been efforts in recent years by members of the general financial and investment communities, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors, to divest themselves and to promote the divestment of securities issued by companies involved in the fossil fuel extraction market, or that have low ratings or scores in studies and assessments of the type noted above, including coal producers. These entities also have been pressuring lenders to limit financing available to such companies. These efforts may have adverse consequences, including, but not limited to:

- restricting our ability to access capital and financial markets in the future;
- reducing the demand and price for our equity securities;
- increasing the cost of borrowing;
- causing a decline in our credit ratings;
- reducing the availability, and/or increasing the cost of, third-party insurance;
- increasing our retention of risk through self-insurance;
- making it more difficult to obtain surety bonds, letters of credit, bank guarantees or other financing; and
- limiting our flexibility in business development activities such as mergers, acquisitions and divestures.

Risks Related to Ownership of Our Securities

The price of our securities may be volatile.

The price of our common stock (Common Stock) may fluctuate due to a variety of market and industry factors that may materially reduce the market price of our Common Stock regardless of our operating performance, including, among others:

- actual or anticipated fluctuations in our quarterly and annual results and those of other public companies in our industry;
- industry cycles and trends;
- mergers and strategic alliances in the coal industry;
- changes in government regulation;
- potential or actual military conflicts or acts of terrorism;
- the failure of securities analysts to publish research about us or to accurately predict the results we actually achieve;
- changes in accounting principles;
- announcements concerning us or our competitors;
- lack of trading liquidity; and
- the general state of the securities market.

In addition, the stock market in general has experienced significant volatility that often has been unrelated to the operating performance of companies whose shares are traded. These market fluctuations could adversely affect the trading price of our Common Stock, regardless of our actual operating performance. As a result of all of these factors, investors in our Common Stock may not be able to resell their stock at or above the price they paid or at all. Further, we could be the subject of securities class action litigation due to any such stock price volatility, which could divert management’s attention and have a material adverse effect on our results of operation.

Our Common Stock is subject to dilution and may be subject to further dilution in the future.

Our Common Stock is subject to dilution from our long-term incentive plan. 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.

There may be circumstances in which the interests of a significant stockholder could be in conflict with other stakeholders' interests.

Circumstances may arise in which the interests of a significant stockholder may be in conflict with the interests of our other stakeholders. A significant stockholder may exert substantial influence over us to cause us to take action that aligns with their interests, for example, to pursue or prevent acquisitions, divestitures or other transactions, including the issuance or repurchase of additional shares or debt, that, in its judgment, could enhance its investment in us or another company in which it invests. Such transactions may advance the interests of the significant stockholder and not necessarily those of other stakeholders, which might adversely affect us or other holders of our Common Stock or debt instruments.

A significant stockholder may also sell shares of our Common Stock into the market from time to time, and we cannot predict the effect, if any, that such future sales may have on the market price of our Common Stock.

The payment of dividends on our stock or repurchases of our stock is dependent on a number of factors, and future payments and repurchases cannot be assured.

Restrictive covenants in our credit facility and in the indenture governing our senior secured notes limit our ability to pay cash dividends and repurchase shares. Other debt instruments to which we or our subsidiaries are, or may be, a party, also contain restrictive covenants that 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 Common Stock. In addition, holders of capital 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 capital 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 leverage and other financial ratios. Accordingly, we cannot make any assurance that future dividends will be paid or future repurchases will be made.

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, 2019, we had gross deferred income tax assets, including net operating loss carryforwards, and liabilities of $2,208.1 million and $140.2 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 $2,068.4 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 income"), which limited our ability to look to future taxable income in assessing the likelihood of realizing those assets.

The Company's ability to use its net operating loss carryforwards may be limited if it experiences an "ownership change" as defined in Section 382 (Section 382) of the Internal Revenue Code of 1986, as amended. An ownership change generally occurs if certain stockholders increase their aggregate percentage ownership of a corporation's stock by more than 50 percentage points over their lowest percentage ownership at any time during the testing period, which is generally the three-year period preceding any potential ownership change.

There is no assurance that the Company will not experience a future ownership change under Section 382 that may significantly limit or possibly eliminate its ability to use its net operating loss carryforwards. Potential future transactions involving the sale or issuance of our Common Stock, including the exercise of conversion options under the terms of any convertible debt that Peabody may issue in the future, the repurchase of such debt with Common Stock, any issuance of Common Stock for cash and the acquisition or disposition of such stock by a stockholder owning 5% or more of our Common Stock, or a combination of such transactions, may increase the possibility that the Company will experience a future ownership change under Section 382.

Under Section 382, a future ownership change would subject the Company to additional annual limitations that apply to the amount of pre-ownership change net operating losses that may be used to offset post-ownership change taxable income. This limitation is generally determined by multiplying the value of a corporation's stock immediately before the ownership change by the applicable long-term tax-exempt rate. Any unused annual limitation may, subject to certain limits, be carried over to later years, and the limitation may under certain circumstances be increased by built-in gains in the assets held by such corporation at the time of the ownership change. This limitation could cause the Company's U.S. federal income taxes to be greater, or to be paid earlier, than they otherwise would be, and could cause all or a portion of the Company's net operating loss carryforwards to expire unused. Similar rules and limitations may apply for state income tax purposes. The Company's ability to use its net operating loss carryforwards will also depend on the amount of taxable income it generates in future periods. Its net operating loss carryforwards may expire before the Company can generate sufficient taxable income to use them in full.

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.

Acquisitions and divestitures are a potentially important part of our long-term strategy, subject to our investment criteria, and involve a number of risks, any of which could cause us not to realize the anticipated benefits.

We may engage in acquisition or divestiture activity based on our set of investment criteria to produce outcomes that increase shareholder value. As it relates to divestitures, we may dispose of certain assets within our portfolio if we determine that the price received is more beneficial to us than keeping the assets within our portfolio. Conversely, acquisitions are a potentially important part of our long-term strategy, and we may pursue acquisition opportunities. If we fail to accurately estimate the future results and value of an acquired or divested business and the related risk associated with such a transaction, or are unable to successfully integrate the businesses or properties we acquire, our business, financial condition or results of operations could be negatively affected. Moreover, any transactions we pursue could materially impact our liquidity and an acquisition could increase capital resource needs and may require us to incur indebtedness, seek equity capital or both. We may not be able to satisfy these liquidity and capital resource needs on acceptable terms or at all. In addition, future acquisitions could result in our assuming significant long-term liabilities relative to the value of the acquisitions.

In addition to the above, any acquisition would be accompanied by risks associated with integrating and assimilating the operations and personnel of any acquired companies, failure to realize the anticipated synergies and maximize the financial and strategic position of the combined enterprise and inability to maintain uniform standards, policies and controls across the organization. Additionally, the acquired companies, assets or properties may have unknown liabilities which could be significant.

Our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt.

Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it more difficult for a third-party to acquire us, even if doing so might be beneficial to our stockholders. Provisions of our by-laws and certificate of incorporation impose various procedural and other requirements that could make it more difficult for stockholders to effect certain corporate actions. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our Common Stock and may have the effect of delaying or preventing a change in control.

Diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results.

The mining industry has limited industry-specific accounting literature and, as a result, we understand diversity in practice exists in the interpretation and application of accounting literature to mining-specific issues. As diversity in mining industry accounting is addressed, we may need to restate our reported results if the resulting interpretations differ from our current accounting practices. Refer to Note 1. “Summary of Significant Accounting Policies” to the accompanying consolidated financial statements for a summary of our significant accounting policies.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

Coal Reserves

We controlled an estimated 4.1 billion tons of proven and probable coal reserves as of December 31, 2019. An estimated 3.6 billion tons of our attributable proven and probable coal reserves are in the U.S., with the remainder in Australia. Approximately 1.5% of our U.S. proven and probable coal reserves, or 53 million tons, are metallurgical coking coal. The remainder of our U.S. coal reserves consists of thermal coal. Approximately 55% of our Australian proven and probable coal reserves, or 269 million tons, are metallurgical coal, comprised of approximately 143 million and 126 million tons of coking coal and low-volatile pulverized coal injection (LV PCI) coals, respectively. The remainder of our Australian coal reserves consists of thermal coal. We own approximately 24% of these reserves and leased property comprises the remaining 76%. Approximately 70% of our reserves, or 2.8 billion tons, are compliance coal and 30% 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 CAA 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.

		Proven and Probable Reserves as of December 31, 2019 (1)		
Mining Segment	**Locations**	**Owned Tons**	**Leased Tons**	**Total Tons**
			(Tons in millions)	
Seaborne Thermal Mining	New South Wales	—	250	250
Seaborne Metallurgical Mining	Queensland, New South Wales and Alabama	—	297	297
Powder River Basin Mining	Wyoming	—	2,309	2,309
Midwestern U.S. Mining	Illinois, Indiana and Kentucky	927	228	1,155
Western U.S. Mining	Arizona, New Mexico and Colorado	32	7	39
Total Proven and Probable Coal Reserves		959	3,091	4,050
Total United States		959	2,597	3,556
Total Australia		—	494	494
Total Proven and Probable Coal Reserves		959	3,091	4,050

(1) Estimated proven and probable coal reserves have been adjusted to account for estimated process dilutions and losses during mining and processing 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 closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.
- *Probable (Indicated) Reserves* — Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our estimates of proven and probable coal reserves are established within these guidelines. Estimates within the proven category have the highest degree of assurance, while estimates within the probable category have only a moderate degree of geologic assurance. Further exploration is necessary to place probable reserves into the proven reserve category. Our active properties generally have a much higher degree of reliability because of increased drilling density.

Our guidelines for geologic assurance surrounding estimated proven and probable U.S. and Australian coal reserves generally follow the respective industry-accepted practices of those countries. In the U.S., our estimated proven coal reserves lie within one-quarter mile of a valid point of measure or point of observation, such as exploratory drill holes or previously mined areas, while our estimated probable coal reserves may lie more than one-quarter mile, but less than three-quarters of a mile, from a point of thickness measurement. In Australia, our estimated proven coal reserves generally lie within 250 meters of a point of observation, while our estimated probable coal reserves may lie more than 250 meters, but less than 500 meters, from a point of observation. For some of our Australian coal reserves, the distance between points of observation is determined by a geostatistical study.

The preparation of our coal reserve estimates is completed in accordance with our prescribed internal control procedures, which include verification of input data into a coal reserve forecasting and economic evaluation software system, as well as multi-functional management review. Our reserve estimates are prepared by our staff of experienced geologists 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 data, surface and coal 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 consider dilutions and losses during mining and processing 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, 2019 reflected a net reduction compared to the prior year of 841 million tons of coal reserves. The decrease was driven by production, changes to our estimates of economic recoverability to reflect current market conditions, mine plan changes and new drilling.

We periodically engage independent mining and geological consultants and consider their input regarding the procedures used by us to prepare our internal estimates of coal reserves, selected property reserve estimates and tabulation of reserve groups according to standard classifications of reliability. There was no audit conducted in 2019, and in coming years we plan to complete additional audits of our reserve estimates on a cyclical basis for each of our major operating regions.

With respect to the accuracy of our coal reserve estimates, our experience is that recovered reserves are within plus or minus 10% of our proven and probable estimates, on average, and our probable estimates are generally within the same statistical degree of accuracy when the necessary drilling is completed to move reserves from the probable to the proven classification.

For each mine or future mine, we employ a market-driven, risk adjusted capital allocation process to guide long-term mine planning of active operations and development projects for economically mineable coal. We refer to this process as Life-of-Mine (LOM) planning. The LOM plan projects, among other things, annual quantities and qualities for each coal product. The saleable product mix for a mine may include multiple thermal and metallurgical products with different targeted qualities. The expected volumes for each mine and product, as well as annual pricing forecasts for each product, developed as described below, and related cost forecasts, developed as described below, are then evaluated to determine the economically recoverable coal in the LOM plan.

Pricing

The pricing information used to establish our reserves includes internal, proprietary price forecasts and existing contract economics, in each case on a mine-by-mine and product-by-product basis. In general, our price forecasts are based on a thorough analytical process utilizing detailed supply and demand models, global economic indicators, projected foreign exchange rates, analyses of price relationships among various commodities, competing fuels analyses, projected steel demand, analyses of supplier costs and other variables. Price forecasts, supply and demand models and other key assumptions and analyses are stress tested against independent third-party research not commissioned by us to confirm the conclusions reached through our analytical processes, and our price forecasts fall within the ranges of the projections included in this third-party research. The development of the analyses, price forecasts, supply and demand models and related assumptions are subject to multiple levels of management review.

Below is a description of some of the specific factors that we evaluate in developing our price forecasts for thermal and metallurgical coal products on a mine-by-mine and product-by-product basis. Differences between the assumptions and analyses included in our price forecasts and realized factors could cause actual pricing to differ from our forecasts.

Thermal. Several factors can influence thermal coal supply and demand and pricing. Demand is sensitive to total electric power generation volumes, which are determined in part by the impact of weather on heating and cooling demand, inter-fuel competition in the electric power generation mix (such as from natural gas and renewable sources), changes in capacity (additions and retirements), competition from other producers, coal stockpiles and policy and regulations. Supply considerations impacting pricing include reserve positions, mining methods, strip ratios, production costs and capacity and the cost of new supply (greenfield developments or extensions at existing mines).

In the United States, natural gas is the most significant substitute for thermal coal for electricity generation and can be one of the largest drivers of shifts in supply and demand and pricing. The competitiveness of natural gas as a generation fuel source has been strengthened by accelerated growth in domestic natural gas production, new natural gas combined cycle generation capacity and comparatively low natural gas prices versus historic levels. The build out of renewable generation and subsidized power can also be a key driver of power market pricing and hence coal prices.

Internationally, thermal coal-fueled generation also competes with alternative forms of electricity generation. The competitiveness and availability of generation fueled by natural gas, oil, nuclear, hydro, wind, solar and biomass vary by country and region and can have a meaningful impact on coal pricing. Policy and regulations, which vary from country to country, can also influence prices. In addition, seaborne thermal coal import demand can be significantly impacted by the availability of domestic coal production, particularly in the two leading coal import countries, China and India, and the competitiveness of seaborne supply from leading thermal coal exporting countries, including Indonesia, Australia, Russia, Colombia, the U.S. and South Africa, among others.

Metallurgical. Several factors can influence metallurgical coal supply and demand and pricing. Demand is impacted by economic conditions, government policies 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. Competition from other types of coal is also a key price consideration and can be impacted by 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 domestic coal production, particularly in leading metallurgical coal import countries such as China, among others, as well as country-specific policies restricting or promoting domestic supply. The competitiveness of seaborne metallurgical coal supply from leading metallurgical coal exporting countries of Australia, the U.S., Russia, Canada, Mongolia and Mozambique, among others, is also an important price consideration.

In addition to the factors noted above, the prices which may be obtained at each individual mine or future mine can be impacted by factors such as (i) the mine's location, which impacts the total delivered energy costs to its customers, (ii) quality characteristics, particularly if they are unique relative to competing mines, (iii) assumed transportation costs and (iv) other mine costs that are contractually passed on to customers in certain commercial relationships.

Costs

The cost estimates we use to establish our reserves are generally estimated according to internal processes that project future costs based on historical costs and expected trends. The estimated costs normally include mining, processing, transportation, royalty, add-on tax and other mining-related costs. Our estimated mining and processing costs reflect projected changes in prices of consumable commodities (mainly diesel fuel, explosives and steel), labor costs, geological and mining conditions, targeted product qualities and other mining-related costs. Estimates for other sales-related costs (mainly transportation, royalty and add-on tax) are based on contractual prices or fixed rates. Specific factors that may impact the cost at our various operations include:

- *Geological settings*. The geological characteristics of each mine are among the most important factors that determine the mining cost. Our geology department conducts the exploration program and provides geological models for the LOM process. Coal seam depth, thickness, dipping angle, partings and quality constrain the available mining methods and size of operations. Shallow coal is typically mined by surface mining methods by which the primary cost is overburden removal. Deep coal is typically mined by underground mining methods where the primary costs include coal extraction, conveyance and roof control.
- *Scale of operations and the equipment sizes*. For surface mines, our dragline systems generally have a lower unit cost than truck-and-shovel systems for overburden removal. The longwall operations generally are more cost effective than room-and-pillar operations for underground mines.
- *Commodity prices*. For surface mines, the costs of diesel fuel and explosives are major components of the total mining cost. For underground mines, the steel used for roof bolts represents a significant cost. Forecasted commodity prices are used to project those costs in the financial models we use to establish our reserves.
- *Target product quality*. By targeting a premium quality product, our mining and processing processes may experience more coal losses. By lowering product quality the coal losses can be minimized and therefore a lower cost per ton can be achieved. In our mine plans, the product qualities are estimated to correspond to existing contracts and forecasted market demands.
- *Transportation costs*. Transportation costs vary by region. Most of our U.S. thermal operations sell coal at mine loadouts. Therefore, no transportation expenses are included in our U.S. thermal cost estimates. Our seaborne operations typically sell coal at designated ports. The estimated costs for our seaborne operations include rail and barge transportation and related fees at ports.
- *Royalty costs*. Our royalty costs are based upon contractual agreements for the coal leased from governments or private owners. The royalty rates for coal leased from governments differ by country and, in some cases, by mining method. Estimated add-on taxes and other sales-related costs are determined according to government regulations or historical costs.
- *Exchange rates*. Costs related to our Australian production are predominantly denominated in Australian dollars, while the Australian coal that we export is sold in U.S. dollars. As a result, Australian/U.S. dollar exchange rates impact the U.S. dollar cost of Australian production.

Based on our mine-by-mine and product-by-product evaluations of the estimated prices for our coal, and the costs and expenses of mining and selling our coal, we have concluded our reserves were economically recoverable as of December 31, 2019.

On October 31, 2018, the SEC voted to adopt amendments to modernize the property disclosure requirements for mining registrants and related guidance under the Securities Act of 1933 and the Securities Exchange Act of 1934. The final rules provide a three-year transition period, thus, we will be required to begin to comply with the new rules for the fiscal year beginning on January 1, 2021 (reported in the Annual Report on Form 10-K for the year ended December 31, 2021). We are in the process of assessing the impact the new rules will have on our disclosures.

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 Alabama, Colorado and New Mexico. 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, 2019, we leased 1,610 acres of federal land in Alabama, 6,107 acres in Colorado, 640 acres in New Mexico and 38,915 acres in Wyoming, for a total of 47,272 acres nationwide subject to those limitations.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 64,783 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.

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 court process. Surface rights are typically acquired directly from landowners through agreement or court determination, subject to some exceptions.

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.

The following charts provide a summary, by mining complex, of production (in descending order by mining segment) for the years ended December 31, 2019, 2018 and 2017, tonnage of coal reserves that are assigned to our active operating mines, our property interest in those reserves and other characteristics of the facilities.

SUMMARY OF COAL PRODUCTION AND SULFUR CONTENT OF ASSIGNED RESERVES
(Tons in millions)

	Production				Sulfur Content of Assigned Reserves as of December 31, 2019 (1)			
	Year Ended December 31,			Type of	<1.2 lbs. Sulfur Dioxide per	>1.2 to 2.5 lbs. Sulfur Dioxide per	>2.5 lbs. Sulfur Dioxide per	As Received Btu per
Segment/Mining Complex	2019	2018	2017	Coal	Million Btu	Million Btu	Million Btu	pound (2)
Seaborne Thermal Mining:								
Wilpinjong	14.1	14.1	13.4	T	104	—	—	10,000
Wambo (3)	5.6	5.2	5.9	T/C	146	—	—	11,300
Total	19.7	19.3	19.3		250	—	—	
Seaborne Metallurgical Mining:								
Coppabella	2.4	2.7	2.8	P	24	—	—	12,600
Shoal Creek	1.9	0.2	—	C	53	—	—	12,700
Moorvale	1.7	2.1	1.8	C/P/T	8	—	—	12,500
Metropolitan	1.5	1.7	1.0	C/P/T	18	—	—	12,600
Millennium	0.6	1.9	3.3	C/P	—	—	—	12,600
North Goonyella	—	1.4	3.4	C	82	—	—	12,700
Middlemount (4)	—	—	—	C/P	22	—	—	12,400
Total	8.1	10.0	12.3		207	—	—	
Powder River Basin Mining:								
North Antelope Rochelle	85.3	98.3	101.6	T	1,610	—	—	8,800
Caballo	12.6	11.3	11.1	T	447	6	—	8,400
Rawhide	10.1	9.5	10.4	T	200	46	—	8,300
Total	108.0	119.1	123.1		2,257	52	—	
Midwestern U.S. Mining:								
Bear Run	6.8	6.9	7.3	T	4	25	205	10,900
Gateway North	3.0	3.1	2.5	T	—	—	52	10,900
Wild Boar	2.5	2.7	2.7	T	—	—	30	11,100
Francisco Underground	2.0	2.2	2.2	T	—	—	14	11,370
Wildcat Hills Underground (5)	1.4	1.3	1.5	T	—	—	—	12,100
Somerville Central	1.2	2.0	2.2	T	—	—	3	11,000
Cottage Grove (6)	0.1	0.4	0.3	T	—	—	—	—
Total	17.0	18.6	18.7		4	25	304	
Western U.S. Mining:								
El Segundo/Lee Ranch	5.5	5.5	4.9	T	4	23	7	9,100
Kayenta (7)	3.8	6.5	6.2	T	—	—	—	10,600
Twentymile	2.6	3.1	3.8	T	5	—	—	11,200
Total	11.9	15.1	14.9		9	23	7	
Total Assigned	**164.7**	**182.1**	**188.3**		**2,727**	**100**	**311**	

T: Thermal
C: Coking
P: Pulverized Coal Injection Metallurgical

ASSIGNED RESERVES (8)

AS OF DECEMBER 31, 2019

(Tons in millions)

		Attributable Ownership					100% Project Basis					Modifying Factors (9)	
Segment/Mining Complex	Interest	Proven and Probable Reserves	Owned	Leased	Surface	Underground	Proven and Probable Reserves	Owned	Leased	Surface	Underground	ROM Factor	Yield
Seaborne Thermal Mining:													
Wilpinjong	100%	104	—	104	104	—	104	—	104	104	—	104%	90%
Wambo (3)	(a)	146	—	146	36	110	179	—	179	69	110	99%	73%
Total		250	—	250	140	110							
Seaborne Metallurgical Mining:													
Coppabella	73.3%	24	—	24	24	—	33	—	33	33	—	93%	77%
Shoal Creek	100%	53	—	53	—	53	53	—	53	—	53	102%	56%
Moorvale	73.3%	8	—	8	8	—	11	—	11	11	—	117%	80%
Metropolitan	100%	18	—	18	—	18	18	—	18	—	18	117%	78%
Millennium	100%	—	—	—	—	—	—	—	—	—	—	95%	79%
North Goonyella	100%	82	—	82	—	82	82	—	82	—	82	76%	82%
Middlemount (4)	50%	22	—	22	22	—	44	—	44	44	—	85%	77%
Total		207	—	207	54	153							
Powder River Basin Mining:													
North Antelope Rochelle	100%	1,610	—	1,610	1,610	—	1,610	—	1,610	1,610	—	92%	100%
Caballo	100%	453	—	453	453	—	453	—	453	453	—	90%	100%
Rawhide	100%	246	—	246	246	—	246	—	246	246	—	93%	100%
Total		2,309	—	2,309	2,309	—							
Midwestern U.S. Mining:													
Bear Run	100%	234	104	130	234	—	234	104	130	234	—	106%	73%
Gateway North	100%	52	51	1	—	52	52	51	1	—	52	70%	62%
Wild Boar	100%	30	11	19	30	—	30	11	19	30	—	104%	80%
Francisco Underground	100%	14	3	11	—	14	14	3	11	—	14	71%	65%
Wildcat Hills Underground (5)	100%	—	—	—	—	—	—	—	—	—	—	—%	—%
Somerville Central	100%	3	3	—	3	—	3	3	—	3	—	103%	68%
Cottage Grove (6)	100%	—	—	—	—	—	—	—	—	—	—	—%	—%
Total		333	172	161	267	66							
Western U.S. Mining:													
El Segundo/Lee Ranch	100%	34	29	5	34	—	34	29	5	34	—	87%	100%
Kayenta (7)	100%	—	—	—	—	—	—	—	—	—	—	—%	—%
Twentymile	100%	5	3	2	—	5	5	3	2	—	5	119%	67%
Total		39	32	7	34	5							
Total Assigned		3,138	204	2,934	2,804	334							

ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES (8)
AS OF DECEMBER 31, 2019
(Tons in millions)

	Attributable Ownership					100% Project Basis				
	Total Tons		Proven and Probable			Total Tons		Proven and Probable		
Coal Seam Location	Assigned	Unassigned	Reserves	Proven	Probable	Assigned	Unassigned	Reserves	Proven	Probable
Seaborne Thermal Mining (New South Wales)	250	—	250	203	47	283	—	283	211	72
Seaborne Metallurgical Mining:										
Alabama	53	—	53	52	1	53	—	53	52	1
New South Wales	18	—	18	2	16	18	—	18	2	16
Queensland	136	90	226	184	42	170	120	290	232	58
Total	207	90	297	238	59					
Powder River Basin Mining (Wyoming)	2,309	—	2,309	2,202	107	2,309	—	2,309	2,202	107
Midwestern U.S. Mining:										
Illinois	52	719	771	333	438	52	719	771	333	438
Indiana	281	6	287	208	79	281	6	287	208	79
Kentucky (10)	—	97	97	44	53	—	97	97	44	53
Total	333	822	1,155	585	570					
Western U.S. Mining:										
Arizona (7)	—	—	—	—	—	—	—	—	—	—
New Mexico	34	—	34	34	—	34	—	34	34	—
Colorado	5	—	5	5	—	5	—	5	5	—
Total	39	—	39	39	—					
Total Proven and Probable	3,138	912	4,050	3,267	783					

ASSIGNED AND UNASSIGNED - RESERVE CONTROL AND MINING METHOD
AS OF DECEMBER 31, 2019
(Tons in millions)

	Attributable Ownership				100% Project Basis			
	Reserve Control		Mining Method		Reserve Control		Mining Method	
Coal Seam Location	Owned	Leased	Surface	Underground	Owned	Leased	Surface	Underground
Seaborne Thermal Mining (New South Wales)	—	250	140	110	—	283	173	110
Seaborne Metallurgical Mining:								
Alabama	—	53	—	53	—	53	—	53
New South Wales	—	18	—	18	—	18	—	18
Queensland	—	226	60	166	—	290	96	194
Total	—	297	60	237				
Powder River Basin Mining (Wyoming)	—	2,309	2,309	—	—	2,309	2,309	—
Midwestern U.S. Mining:								
Illinois	770	1	—	771	770	1	—	771
Indiana	124	163	274	13	124	163	274	13
Kentucky (10)	33	64	—	97	33	64	—	97
Total	927	228	274	881				
Western U.S. Mining:								
Arizona (7)	—	—	—	—	—	—	—	—
New Mexico	29	5	34	—	29	5	34	—
Colorado	3	2	—	5	3	2	—	5
Total	32	7	34	5				
Total Proven and Probable	959	3,091	2,817	1,233				

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ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES - SULFUR CONTENT
AS OF DECEMBER 31, 2019
(Tons in millions)

		Attributable Ownership			100% Project Basis			
		Sulfur Content (1)			Sulfur Content (1)			
Coal Seam Location	Type of Coal	<1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	<1.2 lbs. Sulfur Dioxide per Million Btu	>1.2 to 2.5 lbs. Sulfur Dioxide per Million Btu	>2.5 lbs. Sulfur Dioxide per Million Btu	As Received Btu per Pound (2)
Seaborne Thermal Mining (New South Wales)	T/C	250	—	—	283	—	—	10,700
Seaborne Metallurgical Mining:								
Alabama	C	53	—	—	53	—	—	12,700
New South Wales	C/P/T	18	—	—	18	—	—	12,600
Queensland	C/P/T	226	—	—	290	—	—	12,400
Total		297	—	—				
Powder River Basin Mining (Wyoming)	T	2,257	52	—	2,257	52	—	8,700
Midwestern U.S. Mining:								
Illinois	T	—	—	771	—	—	771	10,800
Indiana	T	4	25	258	4	25	258	11,000
Kentucky (10)	T	—	—	97	—	—	97	11,800
Total		4	25	1,126				
Western U.S. Mining:								
Arizona (7)	T	—	—	—	—	—	—	—
New Mexico	T	4	23	7	4	23	7	9,150
Colorado	T	5	—	—	5	—	—	11,200
Total		9	23	7				
Total Proven and Probable		2,817	100	1,133				

T: Thermal
C: Coking
P: Pulverized Coal Injection Metallurgical

(1) Compliance coal is defined by Phase II of the CAA 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) Includes the Wambo Open-Cut Mine and the Wambo Underground Mine areas.

(4) Represents our 50% interest in Middlemount, which owns the Middlemount Mine in Queensland, Australia. Because that entity is accounted for as an unconsolidated equity affiliate, 2019, 2018 and 2017 tons produced by Middlemount have been excluded from the "Summary of Coal Production and Sulfur Content of Assigned Reserves" table. Middlemount produced 2.9 million tons, 4.2 million tons, and 4.3 million tons of coal in 2019, 2018 and 2017, respectively (on a 100% basis).

(5) The Company's Wildcat Hills Underground Mine ceased production in December 2019. The shipment of final tons is expected in 2020.

(6) The Company's Cottage Grove Mine closed during July 2019.

(7) The Company's Kayenta Mine closed during August 2019 upon termination of its coal supply agreement with the Navajo Generating Station in Arizona.

(8) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2019. Unassigned reserves represent coal at currently non-producing locations that would require significant new mine development, mining equipment or plant facilities before operations could begin on the property.

(9) The modifying factors reflect the assumptions which are utilized to convert coal quantities and qualities as in ground to run of mine (ROM) coal after mining, and eventually to saleable product coal after processing. Coal reserves are reported as an estimation of the final saleable quantity, which takes into account any losses and dilutions during mining and processing. We generally keep track of coal reserves through in place coal, ROM coal and product coal. In place coal for U.S. underground reserves excludes planned barrier pillars, but includes regular pillars from projected underground extractions. In place coal for Australian underground reserves is exclusive of all planned pillars. The difference is due to historic practice and software used by each country. The ROM factor represents the estimated ROM coal in relation to the coal in place with considerations of coal losses, dilutions and remaining pillars during mining processes. The yield is the ratio of estimated saleable product coal over ROM coal tons with mainly processing loss considered.

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

(a) In December 2019, after receiving the requisite regulatory and permitting approvals, the Company formed an unincorporated joint venture with Glencore, in which the Company holds a 50% interest, to combine the existing operations of the Company's Wambo Open-Cut Mine in Australia with the adjacent coal reserves of Glencore's United Mine. The Wambo reserve is estimated for our 50% interest in United Wambo Joint Venture and 100% interest in Wambo Underground Mine areas.

Item 3. *Legal Proceedings.*

See Note 26. "Commitments and Contingencies" to the accompanying 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 is listed on the New York Stock Exchange, under the symbol "BTU." As of February 18, 2020 there were 137 holders of our Common Stock, as determined by counting our record holders and the number of participants reflected in a security position listing provided to us by the Depository Trust Company (DTC). Because such DTC participants are brokers and other institutions holding shares of our Common Stock on behalf of their customers, we do not know the actual number of unique shareholders represented by these record holders.

Dividend Policy

The payment of dividends is subject to certain limitations, as set forth in our debt agreements. Such limitations on dividends are discussed in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations." We declared and paid quarterly dividends every quarter in 2019, and a supplemental dividend was declared and paid during the first quarter of 2019. We are suspending dividends in 2020 and our Board of Directors will continue to evaluate the declaration and payment of dividends in the future and the amount of those dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt covenants and other factors that our Board of Directors may deem relevant to such evaluations.

Share Relinquishments

We routinely allow employees to relinquish Common Stock to pay estimated taxes upon the vesting of restricted stock units 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.

Share Repurchase Programs

The Board authorized a share repurchase program, as amended, to allow repurchases of up to $1.5 billion of the outstanding shares of the Company's common stock and/or preferred stock (Repurchase Program). Repurchases may be made from time to time at the Company's discretion. The specific timing, price and size of purchases will depend on the share price, general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time. The Repurchase Program does not have an expiration date and may be discontinued at any time. Through December 31, 2019, we repurchased 41.5 million shares of our Common Stock for $1,340.3 million, which included commissions paid of $0.8 million, leaving $160.5 million available for share repurchase under the Repurchase Program. Limitations on share repurchases imposed by our debt instruments are discussed in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations." We suspended share repurchases in 2019 and no additional repurchases are planned.

Purchases of Equity Securities

The following table summarizes all share purchases for the three months ended December 31, 2019:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Dollar Value of Shares that May Yet Be Used to Repurchase Shares Under the Publicly Announced Program (In millions)
October 1 through October 31, 2019	2,024,905	$ 14.68	2,024,500	$ 160.5
November 1 through November 30, 2019	1,085	9.10	—	160.5
December 1 through December 31, 2019	912	9.09	—	160.5
Total	2,026,902	14.67	2,024,500	

(1) Includes shares withheld to cover the withholding taxes upon the vesting of equity awards, which are not a part of the Repurchase Program.

Mandatory Conversion of Preferred Shares

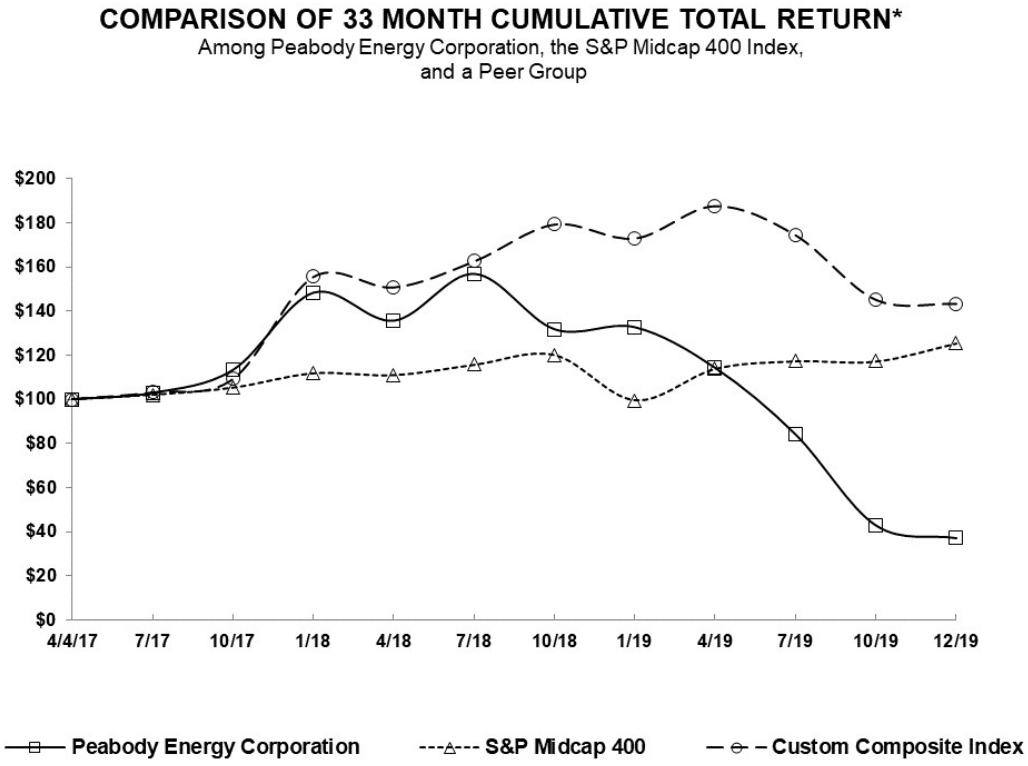
Each share of our Series A Convertible Preferred Stock (Convertible Preferred Stock) that was previously outstanding was subject to mandatory automatic conversion into a number of shares of Common Stock if the volume weighted average price of the Common Stock exceeded $32.50 for at least 45 trading days in a 60 consecutive trading day period, including each of the last 20 days in such 60 consecutive trading day period. On January 31, 2018, the requirements for such a mandatory conversion were met and the then outstanding 13.2 million shares of Convertible Preferred Stock were automatically converted into 24.8 million shares of Common Stock. As a result of this mandatory conversion, we recorded a non-cash preferred dividend charge of $102.5 million during the year ended December 31, 2018. After the mandatory conversion, no shares of Convertible Preferred Stock are issued or outstanding and all rights of the prior holders of Convertible Preferred Stock have terminated.

Stock Performance Graph

The following performance graph compares the cumulative total return on our common stock from April 4, 2017, the date our common stock began trading following the effective date of our Plan, through December 31, 2019, with the cumulative total return of the following indices: (i) the S&P MidCap 400 Stock Index and (ii) a peer group comprised of Arch Coal, Inc., Hallador Energy Co., and Warrior Met Coal, Inc. (Custom Composite Index). The Custom Composite Index reflects publicly listed U.S. companies within the coal industry of similar size or product type. Cloud Peak Energy Inc. was removed from our updated Custom Composite Index as it was delisted by the New York Stock Exchange on March 26, 2019. Master Limited Partnerships were excluded.

The graph assumes that the value of the investment was $100 at April 4, 2017 for BTU and the Custom Composite Index (Warrior Met Coal, Inc. began trading on the New York Stock Exchange on April 13, 2017) and at March 31, 2017, for the S&P Midcap 400 Index. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2019.

These indices are included for comparative purposes only and do not necessarily reflect management's opinion that such indices are an appropriate measure of the relative performance of the stock involved and are not intended to forecast or be indicative of possible future performance of the common stock.



*$100 invested on 4/4/17 in stock or 3/31/17 in index, including reinvestment of dividends.
Fiscal year ending December 31.

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 2019 and 2018 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).

Adjusted EBITDA is used by management as the primary metric to measure our segments’ operating performance. We believe non-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 income (loss) from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing each of our segments’ operating performance, as displayed in the reconciliation. A reconciliation of (loss) income from continuing operations, net of income taxes to Adjusted EBITDA is included on page 58 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, 2019, 2018, 2017, 2016 and 2015 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 consolidated 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.”

References to “Successor” are in reference to reporting dates on or after April 2, 2017; references to “Predecessor” are in reference to reporting dates through April 1, 2017, which include the impact of the Plan provisions and the application of fresh start reporting.

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.

	Successor			Predecessor		
	Year Ended December 31,		April 2 through December 31,	January 1 through	Year Ended December 31,	
	2019	2018	2017	April 1, 2017	2016	2015
	(In millions, except per share data)					
Results of Operations Data						
Total revenues	$ 4,623.4	$ 5,581.8	$ 4,252.6	$ 1,326.2	$ 4,715.3	$ 5,609.2
Costs and expenses	4,561.7	4,920.2	3,588.8	1,113.7	4,935.1	6,995.0
Operating profit (loss)	61.7	661.6	663.8	212.5	(219.8)	(1,385.8)
Interest expense, net	117.2	117.7	135.0	30.2	322.4	525.5
Net periodic benefit costs, excluding service cost	19.4	18.1	21.9	14.4	57.1	79.0
Net mark-to-market adjustment on actuarially determined liabilities	67.4	(125.5)	(45.2)	—	—	—
Reorganization items, net	—	(12.8)	—	627.2	159.0	—
(Loss) income from continuing operations before income taxes	(142.3)	664.1	552.1	(459.3)	(758.3)	(1,990.3)
Income tax provision (benefit)	46.0	18.4	(161.0)	(263.8)	(94.5)	(207.1)
(Loss) income from continuing operations, net of income taxes	(188.3)	645.7	713.1	(195.5)	(663.8)	(1,783.2)
Income (loss) from discontinued operations, net of income taxes	3.2	18.1	(19.8)	(16.2)	(57.6)	(175.0)
Net (loss) income	(185.1)	663.8	693.3	(211.7)	(721.4)	(1,958.2)
Less: Series A Convertible Preferred Stock dividends	—	102.5	179.5	—	—	—
Less: Net income attributable to noncontrolling interests	26.2	16.9	15.2	4.8	7.9	7.1
Net (loss) income attributable to common stockholders	$ (211.3)	$ 544.4	$ 498.6	$ (216.5)	$ (729.3)	$ (1,965.3)
Basic EPS - (Loss) income from continuing operations	$ (2.07)	$ 4.35	$ 3.85	$ (10.93)	$ (36.72)	$ (98.65)
Diluted EPS - (Loss) income from continuing operations	$ (2.07)	$ 4.28	$ 3.81	$ (10.93)	$ (36.72)	$ (98.65)
Weighted average shares used in calculating basic EPS	103.7	119.3	101.1	18.3	18.3	18.1
Weighted average shares used in calculating diluted EPS	103.7	121.0	102.5	18.3	18.3	18.1
Dividends declared per share	$ 2.410	$ 0.485	$ —	$ —	$ —	$ 0.075
Other Data						
Tons produced	164.7	182.1	142.7	45.6	175.6	208.7
Tons sold	165.5	186.7	145.4	46.1	186.8	228.8
Net cash provided by (used in) continuing operations:						
Operating activities	$ 705.4	$ 1,516.9	$ 832.2	$ (804.8)	$ 33.6	$ 69.7
Investing activities	(261.3)	(517.3)	(93.4)	15.1	(244.1)	(290.0)
Financing activities	(701.3)	(1,025.2)	(745.4)	952.3	907.9	267.7
Adjusted EBITDA	837.1	1,379.3	1,145.3	341.3	532.0	432.4
Balance Sheet Data (at period end)						
Total assets	$ 6,542.8	$ 7,423.7	$ 8,181.2	$ 8,266.9	$ 11,777.7	$ 10,946.9
Total long-term debt (including financing leases)	1,310.8	1,367.0	1,460.8	1,881.4	7,791.4	6,241.2
Total stockholders’ equity	2,672.5	3,451.6	3,655.8	3,131.9	181.5	751.7

Adjusted EBITDA is calculated as follows:

	Successor			Predecessor		
	Year Ended December 31,		April 2 through December 31,	January 1 through April 1, 2017	Year Ended December 31,	
	2019	2018	2017		2016	2015
	(Dollars in millions)					
(Loss) income from continuing operations, net of income taxes	$ (188.3)	$ 645.7	$ 713.1	$ (195.5)	$ (663.8)	$ (1,783.2)
Depreciation, depletion and amortization	601.0	679.0	521.6	119.9	465.4	572.2
Asset retirement obligation expenses	58.4	53.0	41.2	14.6	41.8	45.5
Selling and administrative expenses related to debt restructuring	—	—	—	—	21.5	—
Gain on formation of United Wambo Joint Venture	(48.1)	—	—	—	—	—
Asset impairment	270.2	—	—	30.5	247.9	1,277.8
Provision for North Goonyella equipment loss	83.2	66.4	—	—	—	—
North Goonyella insurance recovery - equipment	(91.1)	—	—	—	—	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	(18.8)	(18.3)	(17.3)	(5.2)	(7.5)	3.9
Interest expense	144.0	149.3	119.7	32.9	298.6	465.4
Loss on early debt extinguishment	0.2	2.0	20.9	—	29.5	67.8
Interest income	(27.0)	(33.6)	(5.6)	(2.7)	(5.7)	(7.7)
Net mark-to-market adjustment on actuarially determined liabilities	67.4	(125.5)	(45.2)	—	—	—
Reorganization items, net	—	(12.8)	—	627.2	159.0	—
Gain on disposal of reclamation liability	—	—	(31.2)	—	—	—
Gain on disposal of Burton Mine assets	—	—	(52.2)	—	—	—
Break fees related to terminated asset sales	—	—	(28.0)	—	—	—
Unrealized (gains) losses on economic hedges	(42.2)	(18.3)	23.0	(16.6)	39.8	(2.2)
Unrealized (gains) losses on non-coal trading derivative contracts	(1.2)	0.7	1.5	—	—	—
Fresh start coal inventory revaluation	—	—	67.3	—	—	—
Fresh start take-or-pay contract-based intangible recognition	(16.6)	(26.7)	(22.5)	—	—	—
Income tax provision (benefit)	46.0	18.4	(161.0)	(263.8)	(94.5)	(207.1)
Adjusted EBITDA	$ 837.1	$ 1,379.3	$ 1,145.3	$ 341.3	$ 532.0	$ 432.4

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

Our discussion and analysis of the year ended December 31, 2019 compared to the year ended December 31, 2018 is included herein. For discussion and analysis of the year ended December 31, 2018 compared to the year ended December 31, 2017, please refer to Item 7 of Part II, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2018, which was filed with the SEC on February 27, 2019 and is incorporated by reference herein.

Overview

In 2019, we produced and sold 164.7 million and 165.5 million tons of coal, respectively, from continuing operations.

As of December 31, 2019, we report our results of operations primarily through the following reportable segments: Seaborne Thermal Mining, Seaborne Metallurgical Mining, Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining and Corporate and Other.

During the year ended December 31, 2019, the Cottage Grove Mine in the Midwestern U.S. Mining segment and the Kayenta Mine in the Western U.S. Mining segment shipped their final tons. We also announced the closures of the Wildcat Hills Underground and Somerville Central Mines in the Midwestern U.S. Mining segment, with both of those operations expecting to ship their final tons in 2020. Due to these changes, we will update our reportable segments beginning in the first quarter of 2020 to combine the Midwestern U.S. Mining segment with the Western U.S. Mining segment, which reflects the manner in which our CODM views our businesses going forward for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. Beginning the first quarter of 2020, we will report our results of operations primarily through the following reportable segments: Seaborne Thermal Mining, Seaborne Metallurgical Mining, Powder River Basin Mining, Other U.S. Thermal Mining and Corporate and Other.

The business of our seaborne operating platform is primarily export focused with customers spread across several countries, with a portion of our thermal and metallurgical coal 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. We classify our seaborne mines within the Seaborne Thermal Mining or Seaborne Metallurgical 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 Seaborne Thermal Mining segment is of a metallurgical grade. Similarly, a small portion of the coal mined by the Seaborne Metallurgical Mining segment is of a thermal 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 Seaborne Thermal Mining operations consist of mines in New South Wales, Australia. The mines in that segment utilize both surface and underground extraction processes to mine low-sulfur, high Btu thermal coal.

Our Seaborne Metallurgical Mining operations consist of mines in Queensland, Australia, one in New South Wales, Australia and one in Alabama. The mines in that segment utilize both surface and underground extraction processes 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 PCI coal.

The principal business of our thermal 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 relatively small 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 historically reflect the aggregation of our New Mexico, Arizona and Colorado mining operations. The mines in that segment are characterized by a mix of surface and underground mining extraction processes and 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.

Our Corporate and Other segment includes selling and administrative expenses, including our technical and shared services functions, results from equity affiliates, corporate hedging activities, trading and brokerage activities, certain 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 commercial matters.

Resource Management. As of December 31, 2019, we controlled approximately 4.1 billion tons of proven and probable coal reserves and approximately 500,000 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 Abbot Point Coal Terminal, with some capacity also secured at Dalrymple Bay Coal Terminal. Mining operations first commenced at the Middlemount Mine in late 2011. During the years ended December 31, 2019, 2018 and 2017, the mine sold 2.9 million, 4.2 million and 4.2 million tons of coal, respectively (on a 100% basis).

North Goonyella Mine

Our North Goonyella Mine in Queensland, Australia experienced a fire in a portion of the mine during September 2018 and mining operations have been suspended since then. No mine personnel were physically harmed by the September 2018 events. On November 13, 2018, the QMI initiated an investigation into the events that occurred at the mine to determine the cause of the event, assess the response to it and make recommendations to reduce the possibility of future incidents and improve response.

During the first quarter of 2019, we completed segmenting of the mine into multiple zones to facilitate a phased reventilation and re-entry of the mine. We commenced reventilation of the first zone of the mine during the second quarter of 2019 and subsequently re-entered the area in the third quarter. Following these activities and a detailed review and assessment of North Goonyella, we determined that due to the time, cost and required regulatory approach to ventilate and re-enter the rest of the mine, we will not pursue attempts to access certain portions of the mine through existing mine workings, but instead will move to the southern panels. We are currently in discussions with the QMI regarding ventilation and re-entry of the second zone of the current mine configuration. In 2020, we are commencing a commercial process for North Goonyella in conjunction with the existing mine development. The process comes in response to expressions of interest from potential strategic partners and other producers. Commercial outcomes could include a strategic financial partner, a joint venture structure or the complete sale of North Goonyella. Alternatively, the commercial process could be abandoned in the absence of an acceptable outcome. Based on the success of discussions with QMI and/or progression of the commercial process being launched, we will determine the appropriate level, if any, and timing of capital expenditures. We anticipate annual holding costs of approximately $24 million per year in relation to North Goonyella, excluding $16 million in take-or-pay commitments, which we are in discussions to reduce.

During the year ended December 31, 2018, we recorded $58.0 million in containment and idling costs related to the events at North Goonyella and a provision of $66.4 million for expected equipment losses. As work progressed and more information became available, we recorded an additional $111.5 million in containment and idling costs and an additional provision of $83.2 million related to equipment losses during the year ended December 31, 2019. The combined provision includes $50.7 million for the estimated cost to replace leased equipment, $45.6 million related to the cost of Company-owned equipment, $39.7 million related to unrecoverable longwall panel development and $13.6 million of other charges, which represents the best estimate of loss based on the assessments made at December 31, 2019.

In March 2019, we entered into an insurance claim settlement agreement with our insurers and various re-insurers under a combined property damage and business interruption policy and recorded a $125 million insurance recovery, the maximum amount available under the policy above a $50 million deductible. We have collected the full amount of the recovery.

On April 30, 2019, Peabody (Bowen) Pty Ltd entered into an option exercise and release agreement with Yancoal Technology Development Pty Ltd pursuant to which Peabody (Bowen) Pty Ltd exercised an option to acquire from Yancoal Technology Development Pty Ltd the longwall mining equipment used under license at the North Goonyella Mine for $54.2 million, which was consistent with our provision for equipment losses for the related impaired assets.

Results of Operations

Non-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 each of our segments' operating performance.

Also included in the following discussion of our results of operations are references to Revenues per Ton, Costs per Ton and Adjusted EBITDA Margin per Ton for each mining segment. These metrics are used by management to measure each of our mining segments' operating performance. Management believes Costs per Ton and Adjusted EBITDA Margin per Ton best reflect controllable costs and operating results at the mining segment level. We consider all measures reported on a per ton basis to be operating/statistical measures; however, we include reconciliations of the related non-GAAP financial measures (Adjusted EBITDA and Total Reporting Segment Costs) in the "Reconciliation of Non-GAAP Financial Measures" section contained within this Item 7.

In our discussion of liquidity and capital resources, we include references to Free Cash Flow which is also a non-GAAP measure. Free Cash Flow is used by management as a measure of our financial performance and our ability to generate excess cash flow from our business operations.

We believe non-GAAP performance measures are used by investors to measure our operating performance and lenders to measure our ability to incur and service debt. These 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. Refer to the “Reconciliation of Non-GAAP Financial Measures” section contained within this Item 7 for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Summary

Spot pricing for premium low-vol hard coking coal (Premium HCC), premium low-vol pulverized coal injection (Premium PCI) coal, Newcastle index thermal coal and API 5 thermal coal, and prompt month pricing for PRB 8,880 Btu/Lb coal and Illinois Basin 11,500 Btu/Lb coal during the year ended December 31, 2019 is set forth in the table below. Pricing for our Western U.S. Mining segment is not included as there is no similar spot or prompt pricing data available.

The seaborne pricing included in the table below is not necessarily indicative of the pricing we realized during the year ended December 31, 2019 due to quality differentials and the majority of our seaborne sales being executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. Our typical practice is to negotiate pricing for seaborne metallurgical coal contracts on a quarterly, spot or index basis and seaborne thermal coal contracts on an annual, spot or index basis.

In the U.S., the pricing included in the table below is also not necessarily indicative of the pricing we realized during the year ended December 31, 2019 since we generally sell coal under long-term contracts where pricing is determined based on various factors. Such long-term contracts in the U.S. may 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. Competition from alternative fuels such as natural gas and other coal producers may also impact our realized pricing.

	High	Low	Average	December 31, 2019
Premium HCC (1)	$ 215.80	$ 127.30	$ 176.66	$ 136.10
Premium PCI coal (1)	$ 129.85	$ 85.50	$ 110.50	$ 86.65
Newcastle index thermal coal (1)	$ 99.78	$ 62.32	$ 77.74	$ 66.55
API 5 thermal coal (1)	$ 62.87	$ 48.00	$ 54.41	$ 51.30
PRB 8,800 Btu/Lb coal (2)	$ 12.60	$ 12.05	$ 12.22	$ 12.10
Illinois Basin 11,500 Btu/Lb coal (2)	$ 47.50	$ 33.50	$ 38.83	$ 33.65

(1) Prices expressed per tonne.

(2) Prices expressed per ton.

With respect to seaborne metallurgical coal, global steel production increased approximately 3% through the year ended December 31, 2019 as compared to the prior year period. India imports increased approximately 5% through the year ended December 31, 2019, as compared to the prior year, amid domestic steel production growth of approximately 3% year-over-year. Steel production in China increased approximately 7% through the year ended December 31, 2019 as compared to the prior year, resulting in an approximate 15% increase in coking coal imports during the same period. China’s steel production continues to be fueled by infrastructure spending. China’s seaborne demand will remain dependent upon the country’s import policies.

Seaborne thermal coal demand and pricing was subdued due to restrictions in China and low gas prices coupled with elevated stockpiles in Europe, despite robust demand from India and other Asian regions. Chinese thermal coal imports increased by approximately 8 million tonnes through the year ended December 31, 2019 as compared to the prior year. Despite constraints by heightened mine safety inspections, China’s domestic production registered a 4.2% increase through the year ended December 31, 2019, as compared to the prior year period, supported by new mine approvals. India’s domestic production declined approximately 1% through the year ended December 31, 2019, which was not sufficient to meet growing demand from its industrial and power sectors. As a result, India’s thermal coal imports have increased by approximately 6% or 10 million tonnes year-over-year through December 31, 2019. Demand from countries comprising the Association of Southeast Asian Nations (ASEAN) increased 23 million tonnes through the year ended December 31, 2019 as compared to the prior year, primarily led by Vietnam.

In the United States, overall electricity demand was down year-over-year through the year ended December 31, 2019. Continued coal plant retirements, growth in natural gas and renewable generation and weak natural gas prices have negatively impacted coal demand. For the year ended December 31, 2019, utility consumption of PRB coal fell approximately 16% as compared to the prior year due to ongoing pressure from retirements, wind generation and regional natural gas prices that continue to trade at a discount to quoted Henry Hub natural gas spot prices.

Our revenues for the year ended December 31, 2019 decreased as compared to the same period in 2018 ($958.4 million) primarily due to lower sales volumes and realized prices. Our Seaborne Metallurgical Mining segment was adversely impacted by the events at our North Goonyella Mine described above, as well as other production factors, partially offset by the incremental volume provided by our Shoal Creek Mine. Our Powder River Basin Mining segment was adversely impacted by lower demand and delays in rail shipments caused by severe flooding during the first half of 2019.

Results from continuing operations, net of income taxes for the year ended December 31, 2019 decreased as compared to the same period in the prior year ($834.0 million). The decrease was driven by the unfavorable revenue variances described above, as well as asset impairment charges recorded in the current period ($270.2 million), the impact of a net mark-to-market loss on actuarially determined liabilities as compared to a gain in the prior year ($192.9 million) and approximately $20 million of expense in the current year related to the Monto litigation. These unfavorable variances were partially offset by reduced operating costs and expenses owing largely to the sales volume decline as well as production efficiencies and other cost improvements ($534.8 million) and an insurance recovery related to the events at our North Goonyella Mine ($125.0 million).

The decrease in net results attributable to common stockholders during the year ended December 31, 2019 as compared to the same period in 2018 was partially offset by dividends ($102.5 million) recorded in the prior year period related to the convertible preferred stock issued in connection with our reorganization. Adjusted EBITDA for the year ended December 31, 2019 reflected a year-over-year decrease of $542.2 million.

As of December 31, 2019, our available liquidity was approximately $1.3 billion. Refer to the “Liquidity and Capital Resources” section contained within this Item 7 for a further discussion of factors affecting our available liquidity.

Tons Sold

The following table presents tons sold by operating segment:

	Successor		Increase (Decrease)	
	Year Ended December 31,		to Volumes	
	2019	2018	Tons	%
	(Tons in millions)			
Seaborne Thermal Mining	19.5	19.1	0.4	2.1 %
Seaborne Metallurgical Mining	8.1	11.0	(2.9)	(26.4)%
Powder River Basin Mining	108.1	120.3	(12.2)	(10.1)%
Midwestern U.S. Mining	16.0	18.9	(2.9)	(15.3)%
Western U.S. Mining	11.9	14.7	(2.8)	(19.0)%
Total tons sold from mining segments	163.6	184.0	(20.4)	(11.1)%
Corporate and Other	1.9	2.7	(0.8)	(29.6)%
Total tons sold	165.5	186.7	(21.2)	(11.4)%

Supplemental Financial Data

The following table presents supplemental financial data by operating segment:

	Successor Year Ended December 31, 2019	Successor Year Ended December 31, 2018	(Decrease) Increase $	(Decrease) Increase %
Revenues per Ton - Mining Operations (1)				
Seaborne Thermal	$ 49.69	$ 57.58	$ (7.89)	(13.7)%
Seaborne Metallurgical	127.62	141.06	(13.44)	(9.5)%
Powder River Basin	11.37	11.84	(0.47)	(4.0)%
Midwestern U.S.	41.90	42.44	(0.54)	(1.3)%
Western U.S.	53.48	40.20	13.28	33.0 %
Costs per Ton - Mining Operations (1) (2)				
Seaborne Thermal	$ 32.84	$ 33.90	$ (1.06)	(3.1)%
Seaborne Metallurgical (3)	110.30	100.97	9.33	9.2 %
Powder River Basin	9.32	9.47	(0.15)	(1.6)%
Midwestern U.S.	33.72	34.75	(1.03)	(3.0)%
Western U.S.	34.19	30.33	3.86	12.7 %
Adjusted EBITDA Margin per Ton - Mining Operations (1) (2)				
Seaborne Thermal	$ 16.85	$ 23.68	$ (6.83)	(28.8)%
Seaborne Metallurgical (3)	17.32	40.09	(22.77)	(56.8)%
Powder River Basin	2.05	2.37	(0.32)	(13.5)%
Midwestern U.S.	8.18	7.69	0.49	6.4 %
Western U.S.	19.29	9.87	9.42	95.4 %

(1) This is an operating/statistical measure not recognized in accordance with U.S. GAAP. Refer to the "Reconciliation of Non-GAAP Financial Measures" section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

(2) Includes revenue-based production taxes and royalties; excludes depreciation, depletion and amortization; asset retirement obligation expenses; selling and administrative expenses; restructuring charges; asset impairment; provision for North Goonyella equipment loss and related insurance recovery; amortization of fresh start reporting adjustments related to take-or-pay contract-based intangibles; and certain other costs related to post-mining activities.

(3) Includes the events at the North Goonyella Mine resulting in additional Costs per Ton and lower Adjusted EBITDA Margin per Ton for Seaborne Metallurgical of $9.59 and $5.27 for the years ended December 31, 2019 and 2018, respectively.

Revenues

The following table presents revenues by reporting segment:

	Successor Year Ended December 31, 2019	Successor Year Ended December 31, 2018	(Decrease) Increase to Revenues $	(Decrease) Increase to Revenues %
	(Dollars in millions)			
Seaborne Thermal Mining	$ 971.7	$ 1,099.2	$ (127.5)	(11.6)%
Seaborne Metallurgical Mining	1,033.1	1,553.0	(519.9)	(33.5)%
Powder River Basin Mining	1,228.7	1,424.8	(196.1)	(13.8)%
Midwestern U.S. Mining	669.7	801.0	(131.3)	(16.4)%
Western U.S. Mining	639.7	592.0	47.7	8.1 %
Corporate and Other	80.5	111.8	(31.3)	(28.0)%
Revenues	$ 4,623.4	$ 5,581.8	$ (958.4)	(17.2)%

Seaborne Thermal Mining. The decrease in our Seaborne Thermal Mining segment revenues for the year ended December 31, 2019 compared to the prior year was primarily driven by unfavorable realized coal pricing ($131.9 million), partially offset by favorable volume and mix variances ($4.4 million).

Seaborne Metallurgical Mining. Segment revenues decreased during the year ended December 31, 2019 compared to the same period in the prior year primarily due to unfavorable volumes (2.9 million tons, $441.1 million). The unfavorable volume variance resulting from the transition to highwall mining at our Millennium Mine in September 2018, an extended longwall move at our Metropolitan Mine and various mine sequencing impacts (3.2 million tons, $424.4 million) and no current year volume from our North Goonyella Mine (1.7 million tons, $337.6 million) was partially offset by incremental volume provided by our Shoal Creek Mine, acquired in December 2018 (2.0 million tons, $320.9 million). Segment revenues were further impacted by lower realized pricing ($78.8 million).

Powder River Basin Mining. Segment revenues decreased during the year ended December 31, 2019 compared to the same period in the prior year due to lower volume primarily attributable to lower demand and railroad closures and delays that resulted from severe flooding across the upper Great Plains during the first half of 2019 ($157.9 million) and unfavorable realized pricing ($57.9 million). These unfavorable variances were partially offset by a favorable contract settlement with a PRB customer ($19.7 million).

Midwestern U.S. Mining. Segment revenues decreased during the year ended December 31, 2019 compared to the same period in the prior year primarily due to lower demand-based volume ($124.0 million) and unfavorable realized pricing ($7.3 million).

Western U.S. Mining. Segment revenues increased during the year ended December 31, 2019 compared to the same period in the prior year due to revenues associated with the final commercial negotiations for the Kayenta Mine ($127.8 million), offset by an unfavorable volume and mix variance ($75.7 million) and unfavorable realized pricing ($4.4 million).

Corporate and Other. Segment revenues decreased during the year ended December 31, 2019 compared to the same period in the prior year primarily due to lower results on economic hedges.

Adjusted EBITDA

The following table presents Adjusted EBITDA for each of our reporting segments:

	Successor		(Decrease) Increase to	
	Year Ended December 31,		Adjusted EBITDA	
	2019	2018	$	%
	(Dollars in millions)			
Seaborne Thermal Mining	$ 329.4	$ 452.0	$ (122.6)	(27.1)%
Seaborne Metallurgical Mining	140.2	441.4	(301.2)	(68.2)%
Powder River Basin Mining	221.2	284.5	(63.3)	(22.2)%
Midwestern U.S. Mining	130.7	145.2	(14.5)	(10.0)%
Western U.S. Mining	230.7	145.4	85.3	58.7 %
Corporate and Other	(215.1)	(89.2)	(125.9)	(141.1)%
Adjusted EBITDA (1)	$ 837.1	$ 1,379.3	$ (542.2)	(39.3)%

(1) This is a financial measure not recognized in accordance with U.S. GAAP. Refer to the “Reconciliation of Non-GAAP Financial Measures” section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Seaborne Thermal Mining. Segment Adjusted EBITDA decreased during the year ended December 31, 2019 compared to the same period in the prior year as a result of lower realized net coal pricing ($121.7 million) and unfavorable mine sequencing impacts and higher equipment maintenance costs among our thermal surface mines ($48.1 million), offset by improved longwall performance at our Wambo Underground Mine ($30.2 million) and favorable foreign currency impacts ($24.1 million).

Seaborne Metallurgical Mining. Segment Adjusted EBITDA decreased during the year ended December 31, 2019 compared to the same period in the prior year due to unfavorable volume variances described above ($231.9 million). The impact of the negative volumes at our Australian mines ($356.8 million) was partially offset by the incremental volume provided by our Shoal Creek Mine ($124.9 million). The decrease in Segment Adjusted EBITDA was further impacted by lower realized net coal pricing ($71.6 million), mine sequencing impacts among our metallurgical surface operations ($62.6 million) and the net containment and holding costs at our North Goonyella Mine ($19.6 million). These negative variances were partially offset by favorable foreign currency impacts ($50.5 million).

Powder River Basin Mining. Segment Adjusted EBITDA decreased during the year ended December 31, 2019 compared to the same period in the prior year due to the impact of lower volume ($78.7 million) described above, lower realized net coal pricing ($10.7 million) and unfavorable mine sequencing impacts ($10.0 million), partially offset by the net impact of the favorable contract settlement with a PRB customer ($24.0 million) and lower lease expenses due to early lease buyouts ($8.6 million).

Midwestern U.S. Mining. Segment Adjusted EBITDA decreased during the year ended December 31, 2019 compared to the same period in the prior year primarily due to the impact of lower volume ($18.7 million) and lower realized net coal pricing ($2.0 million), partially offset by lower costs for materials, services and repairs ($4.2 million) and lower pricing for fuel and explosives ($3.2 million).

Western U.S. Mining. Segment Adjusted EBITDA increased during the year ended December 31, 2019 compared to the same period in the prior year primarily due to the net impact associated with the final commercial negotiations for the Kayenta Mine ($83.3 million).

Corporate and Other Adjusted EBITDA. The following table presents a summary of the components of Corporate and Other Adjusted EBITDA:

	Successor		(Decrease) Increase	
	Year Ended December 31,		to Income	
	2019	2018	$	%
	(Dollars in millions)			
Middlemount (1)	$ (9.8)	$ 51.1	$ (60.9)	(119.2)%
Resource management activities (2)	8.2	44.7	(36.5)	(81.7)%
Selling and administrative expenses	(145.0)	(158.1)	13.1	8.3 %
Restructuring charges	(24.3)	(1.2)	(23.1)	(1,925.0)%
Transaction costs related to business combinations and joint ventures	(21.6)	(7.4)	(14.2)	(191.9)%
Other items, net (3)	(22.6)	(18.3)	(4.3)	(23.5)%
Corporate and Other Adjusted EBITDA	$ (215.1)	$ (89.2)	$ (125.9)	(141.1)%

(1) Middlemount's results are before the impact of related changes in deferred tax asset valuation allowance and reserves and amortization of basis difference. Middlemount's standalone results included (on a 50% attributable basis) aggregate amounts of depreciation, depletion and amortization, asset retirement obligation expenses, net interest expense and income taxes of $25.1 million and $46.8 million during the years ended December 31, 2019 and 2018, respectively.

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

(3) Includes trading and brokerage activities, 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 decrease in Corporate and Other Adjusted EBITDA during the year ended December 31, 2019 compared to the same period in the prior year was primarily driven by an unfavorable variance in Middlemount's results due to the temporary suspension of operations and a significant change to the mine plan following a highwall failure mid-2019; resource management gains recorded in the prior year period related to the sale of surplus land assets in Queensland's Bowen Basin ($20.6 million) and the sale of surplus coal resources associated with the Millennium Mine ($20.5 million); restructuring charges recorded in the current year for workforce reductions resulting from actions taken at the the North Goonyella Mine, U.S. mine closures and reductions in overhead and support functions; and increased transaction costs in the current year period related to the PRB Colorado joint venture with Arch. These unfavorable results were partially offset by lower selling and administrative expenses primarily related to outside services and incentive compensation.

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

The following table presents (loss) income from continuing operations, net of income taxes:

	Successor			
	Year Ended December 31,		(Decrease) Increase to Income	
	2019	2018	$	%
	(Dollars in millions)			
Adjusted EBITDA (1)	$ 837.1	$ 1,379.3	$ (542.2)	(39.3)%
Depreciation, depletion and amortization	(601.0)	(679.0)	78.0	11.5 %
Asset retirement obligation expenses	(58.4)	(53.0)	(5.4)	(10.2)%
Gain on formation of United Wambo Joint Venture	48.1	—	48.1	n.m.
Asset impairment	(270.2)	—	(270.2)	n.m.
Provision for North Goonyella equipment loss	(83.2)	(66.4)	(16.8)	(25.3)%
North Goonyella insurance recovery - equipment	91.1	—	91.1	n.m.
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	18.8	18.3	0.5	2.7 %
Interest expense	(144.0)	(149.3)	5.3	3.5 %
Loss on early debt extinguishment	(0.2)	(2.0)	1.8	90.0 %
Interest income	27.0	33.6	(6.6)	(19.6)%
Net mark-to-market adjustment on actuarially determined liabilities	(67.4)	125.5	(192.9)	(153.7)%
Reorganization items, net	—	12.8	(12.8)	(100.0)%
Unrealized gains on economic hedges	42.2	18.3	23.9	130.6 %
Unrealized gains (losses) on non-coal trading derivative contracts	1.2	(0.7)	1.9	271.4 %
Fresh start take-or-pay contract-based intangible recognition	16.6	26.7	(10.1)	(37.8)%
Income tax provision	(46.0)	(18.4)	(27.6)	(150.0)%
(Loss) income from continuing operations, net of income taxes	$ (188.3)	$ 645.7	$ (834.0)	(129.2)%

(1) This is a financial measure not recognized in accordance with U.S. GAAP. Refer to the “Reconciliation of Non-GAAP Financial Measures” section below for definitions and reconciliations to the most comparable measures under U.S. GAAP.

Depreciation, Depletion and Amortization. The following table presents a summary of depreciation, depletion and amortization expense by segment:

	Successor		(Decrease) Increase	
	Year Ended December 31,		to Income	
	2019	2018	$	%
	(Dollars in millions)			
Seaborne Thermal Mining	$ (90.7)	$ (88.4)	$ (2.3)	(2.6)%
Seaborne Metallurgical Mining	(125.3)	(129.8)	4.5	3.5 %
Powder River Basin Mining	(148.5)	(183.4)	34.9	19.0 %
Midwestern U.S. Mining	(94.1)	(121.5)	27.4	22.6 %
Western U.S. Mining	(134.1)	(147.3)	13.2	9.0 %
Corporate and Other	(8.3)	(8.6)	0.3	3.5 %
Total	$ (601.0)	$ (679.0)	$ 78.0	11.5 %

Additionally, the following table presents a summary of our weighted-average depletion rate per ton for active mines in each of our mining segments:

	Successor	
	Year Ended December 31,	
	2019	2018
Seaborne Thermal Mining	$ 1.84	$ 1.79
Seaborne Metallurgical Mining	3.09	0.94
Powder River Basin Mining	0.80	0.81
Midwestern U.S. Mining	1.05	0.89
Western U.S. Mining	1.72	2.29

Depreciation, depletion and amortization expense decreased during the year ended December 31, 2019 as compared to the same period in the prior year primarily due to lower amortization of the fair value of certain U.S. coal supply agreements ($65.9 million), decreased expense at our North Goonyella Mine after the fire due to lower sales volumes and asset impairments ($19.2 million) and decreased expense related to the closures of the Kayenta and Cottage Grove Mines during the third quarter of 2019 ($23.7 million). The acquisition of the Shoal Creek Mine in the fourth quarter of 2018 partly offset the decrease in depreciation, depletion and amortization ($41.0 million) and was the driver of the year-over-year increase in the weighted-average depletion rate per ton for the Seaborne Metallurgical Mining segment.

Gain on Formation of United Wambo Joint Venture. During the year ended December 31, 2019, we recognized a $48.1 million gain upon the formation of the United Wambo Joint Venture. Refer to Note 22. “Other Events” to the accompanying consolidated financial statements for further information regarding the calculation of the gain, which information is incorporated herein by reference.

Asset Impairment. We recognized $270.2 million in aggregate asset impairment charges during the year ended December 31, 2019. Refer to Note 5. “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.

Provision for North Goonyella Equipment Loss. Provisions for equipment losses related to the events at our North Goonyella Mine were recorded during the years ended December 31, 2019 and 2018 as discussed in Note 22. “Other Events” to the accompanying consolidated financial statements. The current year provision is incremental to the provisions recorded during 2018 and represents the best estimate of potential loss associated with these events based on assessments made to date.

North Goonyella Insurance Recovery - Equipment. During the year ended December 31, 2019, we entered into an insurance claim settlement agreement with our insurance providers related to North Goonyella equipment losses and recorded a $125.0 million insurance recovery, as discussed in Note 22. “Other Events” to the accompanying consolidated financial statements. Of this amount, Adjusted EBITDA excludes an allocated amount applicable to total equipment losses recognized at the time of the insurance recovery settlement, which consisted of $24.7 million and $66.4 million recognized during the years ended December 31, 2019 and 2018, respectively. The remaining $33.9 million, applicable to incremental costs and business interruption losses, is included in Adjusted EBITDA for the year ended December 31, 2019.

Interest Income. The decrease in interest income during the year ended December 31, 2019 as compared to the prior year was driven by lower cash balances.

Net Mark-to-Market Adjustment on Actuarially Determined Liabilities. The expense recorded during the year ended December 31, 2019 was driven by decreases to the discount rates for all actuarially determined liabilities ($137.6 million) and the unfavorable impact of changes related to claims and an update to our census data for the postretirement benefits plans ($19.7 million). These decreases were partially offset by actuarial gains on pension assets ($94.5 million).

The gain recorded during the year ended December 31, 2018 was driven by increases to the discount rates ($46.2 million), the favorable impact of changes related to claims ($54.2 million), updates to the Medicare law ($20.0 million) and an update to our census data ($7.7 million) for the postretirement benefit plans. The impact on our pension plans was small as actuarial losses on pension assets were largely offset by an increase in discount rates.

Reorganization Items, Net. The reorganization items recorded during the year ended December 31, 2018 were impacted by a favorable adjustment to our former bankruptcy claims accrual due to settlement of claims.

Unrealized Gains on Economic Hedges. Unrealized gains primarily relate to mark-to-market activity from economic hedge activities intended to hedge future coal sales. For additional information, refer to Note 9. “Derivatives and Fair Value Measurements” to the accompanying consolidated financial statements.

Fresh Start Take-or-Pay Contract-Based Intangible Recognition. Included in the fresh start reporting adjustments were contract-based intangible liabilities for port and rail take-or-pay contracts. During the years ended December 31, 2019 and 2018 we ratably recognized these contract-based intangible liabilities. For additional details, refer to Note 10. “Intangible Contract Assets and Liabilities” to the accompanying consolidated financial statements.

Income Tax Provision. The increase in the income tax provision during the year ended December 31, 2019 as compared to the prior year period was primarily related to the tax impact of the gain on formation of the United Wambo Joint Venture recognized during the fourth quarter of 2019, the year-over-year change in the benefit recorded in continuing operations under the exception provisions within ASC 740-20-45-7 and the prior year tax benefit related to the release of valuation allowance on refundable alternative minimum tax credits . Refer to Note 12. “Income Taxes” to the accompanying consolidated financial statements for additional information.

Net (Loss) Income Attributable to Common Stockholders

The following table presents net (loss) income attributable to common stockholders:

	Successor		(Decrease) Increase to	
	Year Ended December 31,		to Income	
	2019	2018	$	%
	(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$ (188.3)	$ 645.7	$ (834.0)	(129.2)%
Income from discontinued operations, net of income taxes	3.2	18.1	(14.9)	(82.3)%
Net (loss) income	(185.1)	663.8	(848.9)	(127.9)%
Less: Series A Convertible Preferred Stock dividends	—	102.5	(102.5)	(100.0)%
Less: Net income attributable to noncontrolling interests	26.2	16.9	9.3	55.0 %
Net (loss) income attributable to common stockholders	$ (211.3)	$ 544.4	$ (755.7)	(138.8)%

Income from Discontinued Operations, Net of Income Taxes. The decrease in income from discontinued operations, net of income taxes during the year ended December 31, 2019 as compared to the prior year period was primarily driven by smaller actuarial gains associated with black lung liabilities.

Series A Convertible Preferred Stock Dividends. The convertible preferred stock dividends for the year ended December 31, 2018 were comprised of the deemed dividends granted for all remaining shares of convertible preferred stock shares that were converted as of January 31, 2018.

Net Income Attributable to Noncontrolling Interests. The increase in net income attributable to noncontrolling interests during the year ended December 31, 2019 was primarily driven by the gain on formation of the United Wambo Joint Venture recognized during the fourth quarter of 2019.

Diluted EPS

The following table presents diluted EPS:

	Successor		Decrease to	
	Year Ended December 31,		EPS	
	2019	2018	$	%
Diluted EPS attributable to common stockholders:				
(Loss) income from continuing operations	$ (2.07)	$ 4.28	$ (6.35)	(148.4)%
Income from discontinued operations	0.03	0.15	(0.12)	(80.0)%
Net (loss) income attributable to common stockholders	$ (2.04)	$ 4.43	$ (6.47)	(146.0)%

Diluted EPS is commensurate with the changes in results from continuing operations and discontinued operations during that period. Diluted EPS reflects weighted average diluted common shares outstanding of 103.7 million and 121.0 million for the years ended December 31, 2019 and 2018, respectively.

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Reconciliation of Non-GAAP Financial Measures

Adjusted EBITDA is defined as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, depreciation, depletion and amortization and reorganization items, net. Adjusted EBITDA is also adjusted for the discrete items that management excluded in analyzing each of our segment's operating performance, as displayed in the reconciliations below.

	Successor	
	Year Ended December 31,	
	2019	2018
	(Dollars in millions)	
(Loss) income from continuing operations, net of income taxes	$ (188.3)	$ 645.7
Depreciation, depletion and amortization	601.0	679.0
Asset retirement obligation expenses	58.4	53.0
Gain on formation of United Wambo Joint Venture	(48.1)	—
Asset impairment	270.2	—
Provision for North Goonyella equipment loss	83.2	66.4
North Goonyella insurance recovery - equipment	(91.1)	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	(18.8)	(18.3)
Interest expense	144.0	149.3
Loss on early debt extinguishment	0.2	2.0
Interest income	(27.0)	(33.6)
Net mark-to-market adjustment on actuarially determined liabilities	67.4	(125.5)
Reorganization items, net	—	(12.8)
Unrealized gains on economic hedges	(42.2)	(18.3)
Unrealized (gains) losses on non-coal trading derivative contracts	(1.2)	0.7
Fresh start take-or-pay contract-based intangible recognition	(16.6)	(26.7)
Income tax provision	46.0	18.4
Adjusted EBITDA	$ 837.1	$ 1,379.3

Revenues per Ton and Adjusted EBITDA Margin per Ton are equal to revenues by segment and Adjusted EBITDA by segment, respectively, divided by segment tons sold. Costs per Ton is equal to Revenues per Ton less Adjusted EBITDA Margin per Ton, and are reconciled to operating costs and expenses as follows:

	Successor	
	Year Ended December 31,	
	2019	2018
	(Dollars in millions)	
Operating costs and expenses	$ 3,536.6	$ 4,071.4
Unrealized gains (losses) on non-coal trading derivative contracts	1.2	(0.7)
Fresh start take-or-pay contract-based intangible recognition	16.6	26.7
North Goonyella insurance recovery - cost recovery and business interruption	(33.9)	—
Net periodic benefit costs, excluding service cost	19.4	18.1
Restructuring charges	24.3	1.2
Total Reporting Segment Costs	$ 3,564.2	$ 4,116.7

The following table presents Reporting Segment Costs by reporting segment:

	Successor	
	Year Ended December 31,	
	2019	2018
	(Dollars in millions)	
Seaborne Thermal Mining	$ 642.3	$ 647.2
Seaborne Metallurgical Mining	892.9	1,111.6
Powder River Basin Mining	1,007.5	1,140.3
Midwestern U.S. Mining	539.0	655.8
Western U.S. Mining	409.0	446.6
Corporate and Other	73.5	115.2
Total Reporting Segment Costs	$ 3,564.2	$ 4,116.7

The following tables present tons sold, revenues, Reporting Segment Costs and Adjusted EBITDA by reporting segment:

	Successor				
	Year Ended December 31, 2019				
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining
	(Amounts in millions, except per ton data)				
Tons sold	19.5	8.1	108.1	16.0	11.9
Revenues	$ 971.7	$ 1,033.1	$ 1,228.7	$ 669.7	$ 639.7
Reporting Segment Costs	642.3	892.9	1,007.5	539.0	409.0
Adjusted EBITDA	329.4	140.2	221.2	130.7	230.7
Revenues per Ton	$ 49.69	$ 127.62	$ 11.37	$ 41.90	$ 53.48
Costs per Ton	32.84	110.30	9.32	33.72	34.19
Adjusted EBITDA Margin per Ton	16.85	17.32	2.05	8.18	19.29

	Successor				
	Year Ended December 31, 2018				
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining
	(Amounts in millions, except per ton data)				
Tons sold	19.1	11.0	120.3	18.9	14.7
Revenues	$ 1,099.2	$ 1,553.0	$ 1,424.8	$ 801.0	$ 592.0
Reporting Segment Costs	647.2	1,111.6	1,140.3	655.8	446.6
Adjusted EBITDA	452.0	441.4	284.5	145.2	145.4
Revenues per Ton	$ 57.58	$ 141.06	$ 11.84	$ 42.44	$ 40.20
Costs per Ton	33.90	100.97	9.47	34.75	30.33
Adjusted EBITDA Margin per Ton	23.68	40.09	2.37	7.69	9.87

Free Cash Flow is defined as net cash provided by operating activities less net cash used in investing activities and excludes cash outflows related to business combinations. See the table below for a reconciliation of Free Cash Flow to its most comparable measure under U.S. GAAP.

	Successor	
	Year Ended December 31,	
	2019	2018
	(Dollars in millions)	
Net cash provided by operating activities	$ 677.4	$ 1,489.7
Net cash used in investing activities	(261.3)	(517.3)
Add back: Amount attributable to acquisition of Shoal Creek Mine	2.4	387.4
Free Cash Flow	$ 418.5	$ 1,359.8

Outlook

As part of its normal planning and forecasting process, Peabody utilizes a broad approach to develop macroeconomic assumptions for key variables, including country-level gross domestic product (GDP), industrial production, fixed asset investment and third-party inputs, driving detailed supply and demand projections for key demand centers for coal, electricity generation and steel. Specific to the U.S., the Company evaluates individual plant needs, including expected retirements, on a plant by plant basis in developing its demand models. Supply models and cost curves concentrate on major supply regions/countries that impact the regions in which the Company operates.

Our estimates involve risks and uncertainties and are subject to change based on various factors as described more fully in the “Cautionary Notice Regarding Forward-Looking Statements” section contained within this Annual Report on Form 10-K.

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

Near-Term Outlook

Seaborne Thermal Coal. Demand growth continues to be led by the Asia-Pacific region. Continued urbanization trends in Vietnam led to the country approximately doubling its 2019 imports over the prior year and contributed to total ASEAN imports rising some 23 million tonnes. Even with record Chinese domestic coal production, Chinese thermal coal imports rose approximately 4% year-over-year on increased domestic power consumption. In addition, India thermal coal imports increased 6% to 177 million tonnes. As expected, demand in Europe declined as the region continues to shift away from coal-fueled generation.

On the supply side, lower-quality Indonesian and Russian exports rose 29 and 12 million tonnes, respectively, in 2019 over the prior year primarily in response to increased demand from China, India and Vietnam. Australian thermal coal exports rose modestly, while U.S. thermal coal exports declined 25% given unfavorable economics on delivered coal pricing.

Looking ahead, Peabody expects growth from the Asia-Pacific region to mitigate impacts of declines in the Atlantic. Indonesia, Australia and Russia will continue to serve as the major sources of seaborne thermal supply.

Seaborne Metallurgical Coal. Supply and demand balance remains favorable as modest demand growth was met with limited supply growth. Limited new sources of metallurgical coal supply are expected to be largely offset by natural depletion. In 2019, Chinese metallurgical coal imports rose approximately 10 million tonnes on increased pig iron production. India’s metallurgical coal imports continued to rise, growing 5% in 2019 compared to the prior year as the country lacks the domestic quantity and quality to meet its steelmaking needs. Increased steel production from ASEAN nations also continued to support seaborne metallurgical coal demand.

Supply growth was muted in 2019 with rising metallurgical exports from Russia and Australia largely offset by declines in U.S. exports. Looking ahead, Peabody anticipates demand growth to be led by India.

U.S. Thermal Coal. Within the U.S., substantial plant retirements, unfavorable weather conditions, low natural gas prices and continued growth in other available energy sources resulted in an estimated 95 million ton decline in total electric power sector demand in 2019. Coal’s share of the total U.S. electricity generation mix fell to 23% in 2019, compared to 27% in 2018. Declining coal capacity, along with natural gas prices and the availability of other sources of electricity generation are expected to continue to impact total U.S. coal demand.

Long-Term Outlook

Seaborne Fundamentals. Peabody anticipates that seaborne metallurgical coal demand will continue to grow as India increases steel production and China continues to have a significant influence on seaborne balances. On the supply side, we expect Australia to maintain its leading metallurgical coal export position, followed by other key seaborne suppliers - U.S., Canada and Russia, among others.

For seaborne thermal, Peabody expects demand to remain relatively stable as demand growth from ASEAN nations helps offset demand decline elsewhere, including, notably, in the Atlantic markets. Over 80% of seaborne thermal coal demand is projected to come from the Asia-Pacific region as Europe's coal generation continues its secular decline. Seaborne thermal coal will continue to be sourced primarily from seaborne exporters Indonesia and Australia, along with Russia, Colombia, South Africa and the U.S., among others.

U.S. Fundamentals. Coal is expected to remain an important piece of the U.S. electric generation mix, albeit declining from current levels. Peabody expects coal-fueled plant retirements to continue to negatively impact future coal demand. The combination of fluctuations in natural gas prices, growth in renewable generation and other competing fuels, and policy and regulations, among other things, are expected to continue to be a key determinant of future U.S. coal demand.

Liquidity and Capital Resources

Overview

Our primary source of cash is proceeds from the sale of our coal production to customers. We have also generated cash from the sale of non-strategic assets, including coal reserves and surface lands, borrowings under our credit facilities and, from time to time, the issuance of securities. Our primary uses of cash include the cash costs of coal production, capital expenditures, coal reserve lease and royalty payments, debt service costs, finance and operating lease payments, postretirement plans, take-or-pay obligations, post-mining retirement obligations, and selling and administrative expenses. We have also used cash for dividends, share repurchases and early debt retirements. We believe that our capital structure allows us to satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations and cash on hand.

Any future determinations to return capital to stockholders, such as dividends or share repurchases will be at the discretion of our Board of Directors and will depend on a variety of factors, including the restrictions set forth under our debt agreements, our net income or other sources of cash, liquidity position and potential alternative uses of cash, such as internal development projects or acquisitions, as well as economic conditions and expected future financial results. Our ability to declare dividends, repurchase shares, or early retire debt in the future will depend on our future financial performance, which in turn depends on the successful implementation of our strategy and on financial, competitive, regulatory, technical and other factors, general economic conditions, demand for and selling prices of coal and other factors specific to our industry, many of which are beyond our control.

Total Indebtedness. Our total indebtedness as of December 31, 2019 and 2018 consisted of the following:

	December 31,	
	2019	2018
	(Dollars in millions)	
6.000% Senior Secured Notes due March 2022	$ 459.0	$ 500.0
6.375% Senior Secured Notes due March 2025	500.0	500.0
Senior Secured Term Loan due 2025, net of original issue discount	392.1	395.9
Finance lease and other obligations	15.2	40.0
Less: Debt issuance costs	(55.5)	(68.9)
	1,310.8	1,367.0
Less: Current portion of long-term debt	18.3	36.5
Long-term debt	$ 1,292.5	$ 1,330.5

Refer to Note 14. "Long-term Debt" to the accompanying consolidated financial statements for further information regarding our indebtedness.

Liquidity

As of December 31, 2019, our available liquidity was $1,275.8 million, which was comprised of cash and cash equivalents and availability under our revolving credit facility and receivables securitization program described below. As of December 31, 2019, our cash balances totaled $732.2 million, including approximately $644.9 million held by U.S. entities, $62.8 million held by Australian subsidiaries, and the remaining balance held by other foreign subsidiaries. A significant majority of the cash held by our foreign subsidiaries is in accounts domiciled in the U.S. and denominated in U.S. dollars. This cash is generally used to support non-U.S. liquidity needs, including capital and operating expenditures in Australia. During 2019, we repatriated to the U.S. approximately $420 million previously held by foreign subsidiaries. If we repatriate additional foreign-held cash in the future, we do not expect restrictions or potential taxes to have a material effect on our overall liquidity.

During the year ended December 31, 2019, we paid dividends of $258.1 million, including $200 million for a supplemental dividend, made stock repurchases totaling $329.9 million, and made open-market purchases of $41.0 million of our senior secured notes for $39.9 million, plus accrued interest. No additional dividends or stock repurchases are currently planned.

Our ability to maintain adequate liquidity depends on the successful operation of our business and appropriate management of operating expenses and capital spending. Our anticipated liquidity needs are highly sensitive to changes in these and other factors.

Debt Financing

As described in Note 14. “Long-term Debt” of the accompanying consolidated financial statements, during 2017, we entered into an indenture related to the issuance of $500.0 million of 6.000% senior secured notes due March 2022 and $500.0 million of 6.375% senior secured notes due March 2025. We make semi-annual interest payments on the senior notes each March 31 and September 30 until maturity. Also during 2017, we entered into a credit agreement and related term loan under which we originally borrowed $950.0 million and have repaid $557.0 million through December 31, 2019. The term loan requires quarterly principal payments of $1.0 million and periodic interest payments, currently at LIBOR plus 2.75%, through December 2024 with the remaining balance due in March 2025.

We also entered into a revolving credit facility allowable under our credit agreement during 2017 for an aggregate commitment of $350.0 million for general corporate purposes. In September 2019, we entered into an amendment to the credit agreement which increased the aggregate commitment amount under the revolver to $565.0 million and, beginning in 2020, makes applicable interest rates and fees dependent upon our periodically-determined first lien leverage ratio, as defined in the credit agreement. To date, we have only utilized this revolving credit facility for letters of credit which incur combined fees of 3.375%, while unused capacity bears a commitment fee of 0.5%. As of December 31, 2019, such letters of credit amounted to $66.4 million and were primarily in support of our reclamation obligations. Availability under the revolver was $498.6 million at December 31, 2019.

Our debt agreements impose various restrictions and limits on certain categories of payments that we may make, such as those for dividends, investments, and stock repurchases. We are also subject to customary affirmative and negative covenants. We were in compliance with all such restrictions and covenants at December 31, 2019.

As described in the “Overview” section contained within Item 1. Business, the September 2019 amendment to our credit facility removed that agreement’s restrictions pertaining to the formation of the PRB Colorado joint venture with Arch. We are currently considering alternatives for addressing similar restrictions contained within the indenture underlying our senior secured notes. Our ability to accomplish this objective is subject to market conditions and other factors, including financing options that may be available to us from time to time and conditions in the credit and debt capital markets generally.

Accounts Receivable Securitization Program

As described in Note 25. “Financial Instruments and Other Guarantees” of the accompanying unaudited condensed consolidated financial statements, we entered into an amended accounts receivable securitization program during 2017 which currently expires in 2022. The program provides for up to $250.0 million in funding, limited to the availability of eligible receivables, accounted for as a secured borrowing. Funding capacity under the program may also be provided for letters of credit in support of other obligations. At December 31, 2019, we had no outstanding borrowings and $132.7 million of letters of credit provided under the program. The letters of credit are primarily in support of portions of our obligations for reclamation, workers’ compensation and postretirement benefits. Availability under the program, which is adjusted for certain ineligible receivables, was $45.0 million at December 31, 2019 and there was no cash collateral requirement.

Capital Requirements

Additions to Property, Plant, Equipment and Mine Development. For 2020, we are targeting capital expenditures of approximately $250 million, which includes approximately $100 million for ongoing extension projects related to our Seaborne Thermal Mining segment, and approximately $150 million in sustaining capital across our portfolio of mines. We plan to consider other growth and development projects across our global platform beyond 2020 and will continue to evaluate the timing associated with those projects based on changes in global coal supply and demand. We have no substantial future payment requirements under U.S. federal coal reserve leases.

Pension and Postretirement Benefit Contributions. Annual contributions to qualified pension plans are made in accordance with minimum funding standards and our agreement with the Pension Benefit Guaranty Corporation. Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). Subsequent to the Effective Date, we no longer sponsor any non-qualified plans. During 2019, we made discretionary contributions of $20.0 million to our qualified pension plans and $17.0 million to our postretirement benefit plans. Based upon our current funding status, we have no minimum funding requirement for 2020. From time to time, Peabody may make discretionary contributions to its qualified pension and postretirement benefit plans.

Historical Cash Flows and Free Cash Flow

The following table summarizes our cash flows for the year ended December 31, 2019 and 2018, as reported in the accompanying consolidated financial statements:

	Successor	
	Year Ended December 31,	
	2019	2018
	(Dollars in millions)	
Net cash provided by operating activities	$ 677.4	$ 1,489.7
Net cash used in investing activities	(261.3)	(517.3)
Net cash used in financing activities	(701.3)	(1,025.2)
Net change in cash, cash equivalents and restricted cash	(285.2)	(52.8)
Cash, cash equivalents and restricted cash at beginning of period	1,017.4	1,070.2
Cash, cash equivalents and restricted cash at end of period	$ 732.2	$ 1,017.4
Net cash provided by operating activities	$ 677.4	$ 1,489.7
Net cash used in investing activities	(261.3)	(517.3)
Add back: Acquisition of Shoal Creek Mine	2.4	387.4
Free Cash Flow	$ 418.5	$ 1,359.8

Operating Activities. The decrease in net cash provided by operating activities for the year ended December 31, 2019 compared to the year ended December 31, 2018 was driven by the following:

- A year-over-year decrease in cash from our mining operations;
- A substantial release of collateral obligations during 2018 upon establishing our new surety bonding program in Australia ($323.1 million); and
- An unfavorable change in net cash flows associated with our working capital ($155.4 million)

Investing Activities. The decrease in net cash used in investing activities for the year ended December 31, 2019 compared to the year ended December 31, 2018 was driven by the following:

- Greater expenditures for the acquisition of our Shoal Creek Mine in 2018 ($385.0 million); and
- The receipt of insurance proceeds attributable to North Goonyella Company-owned equipment losses ($23.2 million); partially offset by
- Higher net receipts from related parties for loans and other advances in 2018 ($124.2 million); and
- Lower proceeds from disposals of assets, net of receivables ($46.4 million)

Financing Activities. The decrease in net cash used in financing activities for the year ended December 31, 2019 compared to the year ended December 31, 2018 was driven by the following:

- Lower common stock repurchases ($504.8 million); partially offset by
- Higher dividends paid ($198.5 million), primarily due to a supplemental dividend of $1.85 per share of common stock

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2019:

	Payments Due By Year				
	Total	Less than 1 Year	2 - 3 Years	4 - 5 Years	More than 5 Years
	(Dollars in millions)				
Long-term debt obligations (principal and interest) (1)	$ 1,674.0	$ 81.5	$ 600.7	$ 106.6	$ 885.2
Finance lease obligations (principal and interest)	15.4	14.5	0.8	0.1	—
Operating lease obligations (2)	95.1	33.7	37.2	17.0	7.2
Unconditional purchase obligations (3)	39.7	39.7	—	—	—
Coal reserve lease and royalty obligations	59.4	5.2	10.4	9.5	34.3
Take-or-pay obligations (4)	1,067.3	116.1	185.0	153.9	612.3
Other long-term liabilities (5)	2,958.9	269.7	412.7	278.3	1,998.2
Total contractual cash obligations	$ 5,909.8	$ 560.4	$ 1,246.8	$ 565.4	$ 3,537.2

(1) Represents the original contractual maturities of our long-term debt obligations. The related interest on long-term debt was calculated using rates in effect at December 31, 2019 for the remaining contractual term of the outstanding borrowings.

(2) Excludes contingent rents. Refer to Note 15. “Leases” to the accompanying consolidated financial statements for additional discussion of contingent rental agreements.

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

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

(5) Represents estimated cash outflows for long-term liabilities relating to our postretirement benefit plans, work-related injuries and illnesses, defined benefit pension plans, mine reclamation and end-of-mine closure costs and exploration obligations. Also includes $2 million of required payments to the Voluntary Employees Beneficiary Association (VEBA) established in connection with Patriot’s bankruptcy, as well as $30 million related to the settlement of the United Mine Workers of America (UMWA) 1974 Pension Plan Litigation described in Note 6. “Discontinued Operations” to the accompanying consolidated financial statements.

We do not expect any of the $16.5 million of net unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to various guarantees and financial instruments that carry off-balance-sheet risk and are not reflected in the accompanying consolidated balance sheets. At December 31, 2019, such instruments included $1,609.2 million of surety bonds and $200.5 million of letters of credit. Such financial instruments provide support for our reclamation bonding requirements, lease obligations, insurance policies and various other performance guarantees. We periodically evaluate the instruments for on-balance-sheet treatment based on the amount of exposure under the instrument and the likelihood of required performance. We do not expect any material losses to result from these guarantees or off-balance-sheet instruments in excess of liabilities provided for in our consolidated balance sheets.

We could experience a decline in our liquidity as financial assurances associated with reclamation bonding requirements, surety bonds or other obligations are required to be collateralized by cash or letters of credit.

As described in Note 25. “Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees” to the accompanying consolidated financial statements, we are required to provide various forms of financial assurance in support of our mining reclamation obligations in the jurisdictions in which we operate. Such requirements are typically established by statute or under mining permits. Historically, such assurances have taken the form of third-party instruments such as surety bonds, bank guarantees and letters of credit, as well as self-bonding arrangements in the U.S. Following our emergence from the Chapter 11 Cases, we shifted away from extensive self-bonding in the U.S. in favor of increased usage of surety bonds and similar third-party instruments. This change in practice has had an unfavorable impact on our liquidity due to increased collateral requirements and surety and related fees.

At December 31, 2019, we had total asset retirement obligations of $752.3 million which were backed by a combination of surety bonds, bank guarantees and letters of credit.

Bonding requirement amounts may differ significantly from the related asset retirement obligation because such requirements are calculated under the assumption that reclamation begins currently, whereas our accounting liabilities are discounted from the end of a mine's economic life (when final reclamation work would begin) to the balance sheet date.

Guarantees and Other Financial Instruments with Off-Balance Sheet Risk. See Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees" to our accompanying consolidated financial statements for a discussion of our accounts receivable securitization program and guarantees and other financial instruments with off-balance sheet risk.

Critical Accounting Policies and Estimates

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

Business Combinations. We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets, and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items. Due to the unobservable inputs to the valuation, the fair value would be considered Level 3 in the fair value hierarchy.

Subsequent to the finalization of the purchase price allocation, any adjustments to the recorded values of acquired assets and liabilities would be reflected in the consolidated statements of operations. Once final, it is not permitted to revise the allocation of the original purchase price, even if subsequent events or circumstances prove the original judgments and estimates to be incorrect. The assumptions and judgments made when recording business combinations will have an impact on reported results of operations for many years into the future. See Note 3. "Acquisition of Shoal Creek Mine" to our accompanying consolidated financial statements for additional information regarding business combinations.

Impairment of Long-Lived Assets. We evaluate our long-lived assets held and used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition. We generally do not view short-term declines in thermal and metallurgical coal prices as a triggering event for conducting impairment tests because of historic price volatility. However, we generally view a sustained trend of depressed coal pricing (for example, over periods exceeding one year) as an indicator of potential impairment. Because of the volatile and cyclical nature of coal prices and demand, it is reasonably possible that coal prices may decrease and/or fail to improve in the near term, which, absent sufficient mitigation such as an offsetting reduction in our operating costs, may result in the need for future adjustments to the carrying value of our long-lived mining assets and mining-related investments.

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

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

Impairment charges of $261.2 million of long-lived assets were recorded for the year ended December 31, 2019. The assumptions used are based on our best knowledge at the time we prepare our analysis but can vary significantly due to the volatile and cyclical nature of coal prices and demand, regulatory issues, unforeseen mining conditions, commodity prices and cost of labor. These types of changes may cause us to be unable to recover all or a portion of the carrying value of our long-lived assets. We conducted a review of all other long-lived assets for recoverability as of December 31, 2019 and determined that no further impairment charge was necessary as of that date.

See Note 5. “Asset Impairment” to our accompanying consolidated financial statements for additional information regarding impairment charges.

Income Taxes. We account for income taxes in accordance with accounting guidance which requires deferred tax assets and liabilities to be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is “more likely than not” that some portion or all of the deferred tax asset will not be realized. In our evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. As of December 31, 2019, we had valuation allowances for income taxes totaling $2,068.4 million. If actual results differ from the assumptions made in our annual evaluation of our valuation allowance, we may record a change in valuation allowance through income tax expense in the period such determination is made.

Our liability for unrecognized tax benefits contains uncertainties because management is required to make assumptions and to apply judgment to estimate the exposures associated with our various filing positions. We recognize the tax benefit from an uncertain tax position only if it is “more likely than not” that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position must be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. As of December 31, 2019, we had net unrecognized tax benefits of $16.5 million included in recorded liabilities in the consolidated balance sheet. We believe that our judgments and estimates are reasonable; however, to the extent we prevail in matters for which liabilities have been established, or are required to pay amounts in excess of our recorded liabilities, our effective tax rate in a given period could be materially affected.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Act) was signed into law making significant changes to the Internal Revenue Code. Key provisions of the Act that impact the Company include: (i) repeal of the corporate alternative minimum tax system, (ii) reduction of the U.S. federal corporate tax rate from 35% to 21% and (iii) the inclusion of foreign income from the new global intangible low-taxed income provision of the Act.

See Note 12. “Income Taxes” to the accompanying consolidated financial statements for additional information regarding valuation allowances, unrecognized tax benefits and the Act.

Postretirement Benefit and Pension Liabilities. We have long-term liabilities for our employees’ postretirement benefit costs and defined benefit pension plans. Our pension obligations are funded in accordance with the provisions of applicable laws and our policies. Liabilities for postretirement benefit costs are funded at our discretion. In connection with fresh start reporting, we made an accounting policy election to prospectively record amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods. Expense for the year ended December 31, 2019 for postretirement benefit costs and pension liabilities totaled $24.8 million, while employer contributions were $82.4 million. An actuarial loss of $61.7 million was recorded for the year ended December 31, 2019.

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

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

	For Year Ended December 31, 2019	
	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Health care cost trend rate:		
Effect on total net periodic postretirement benefit cost	$ 2.5	$ (2.3)
Effect on total postretirement benefit obligation	$ 57.3	$ (50.9)

	For Year Ended December 31, 2019	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic postretirement benefit cost	$ 1.3	$ (1.4)
Effect on total postretirement benefit obligation	$ (32.1)	$ 36.7

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

	For Year Ended December 31, 2019	
	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Discount rate:		
Effect on total net periodic pension cost	$ 1.9	$ (2.1)
Effect on defined benefit pension plans' projected benefit obligation	$ (41.3)	$ 45.1
Expected return on assets:		
Effect on total net periodic pension cost	$ (3.7)	$ 3.7

As a result of discretionary contributions made in recent years, our defined benefit pension plans have become nearly fully funded. As a result of the funding level, the asset allocation mix reflected Peabody's target asset mix of 100% fixed income investments and the pensions plans' assets provide a significant hedge to the funded status against interest rate movements. If the discount rate moves, Peabody's actual results would be different than those shown above as substantially all of the change in the discount rate should be offset by changes to the expected return on plan assets.

See Note 17. "Postretirement Health Care and Life Insurance Benefits" and Note 18. "Pension and Savings Plans" to the accompanying consolidated financial statements for additional information regarding postretirement benefit and pension plans.

Asset Retirement Obligations. Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with applicable reclamation laws and regulations in the U.S. and Australia as defined by each mining permit. Asset retirement obligations are determined for each mine using various estimates and assumptions including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage and the timing of these cash flows, discounted using a credit-adjusted, risk-free rate. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Moreover, regulatory changes could increase our obligation to perform reclamation and mine closing activities. In connection with fresh start reporting, we made an accounting policy election to classify the amortization associated with our asset retirement obligation assets within “Depreciation, depletion and amortization” in the consolidated statements of operations, rather than within “Asset retirement obligation expenses”, as in Predecessor periods. Amortization associated with our asset retirement obligation assets was $100.8 million for the year ended December 31, 2019. Asset retirement obligation expenses for the year ended December 31, 2019 was $58.4 million and payments totaled $54.2 million. See Note 16. “Asset Retirement Obligations” to the accompanying consolidated financial statements for additional information regarding our asset retirement obligations.

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

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

Accrued contingent liabilities exclude claims against third parties and are not discounted. The current portion of these accruals is included in “Accounts payables and accrued expenses” and the long-term portion is included in “Other noncurrent liabilities” in our consolidated balance sheets. In general, legal fees related to environmental remediation and litigation are charged to expense. We include the interest component of any litigation-related penalties within “Interest expense” in our consolidated statements of operations. See Note 26. “Commitments and Contingencies” to the accompanying consolidated financial statements for further discussion of our contingent liabilities.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

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

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

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

Coal Trading Activities and Related Commodity Price Risk

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

We generally account for our coal trading activities using the fair value method, which requires us to reflect contracts with third parties that meet the definition of a derivative at market value in our consolidated financial statements, with the exception of contracts for which we have elected to apply the normal purchases and normal sales exception. Our trading portfolio included futures, forwards and options as of December 31, 2019. The use of VaR allows us to quantify in dollars, on a daily basis, a measure of price risk inherent in our trading portfolio. VaR represents the expected loss in portfolio value due to adverse market price movements over a defined time horizon (liquidation period) within a specified confidence level. Our VaR model is based on a variance/co-variance approach, which captures our potential loss exposure related to future, forward, swap and option positions. Our VaR model assumes a 15-day holding period at the time of VaR measurement and produces an output corresponding with a 95% one-tailed confidence interval, which means that there is a one in 20 statistical chance that our portfolio could lose more than the VaR estimates during the assumed liquidation period. Our volatility calculation incorporates an exponentially weighted moving average algorithm based on price movements during the previous 60 market days, which makes our volatility more representative of recent market conditions while still reflecting an awareness of historical price movements. VaR does not estimate the maximum potential loss expected in the 5% of the time that changes in the portfolio value during the assumed liquidation period is expected to exceed measured VaR. We use stress testing and scenario analysis to help provide visibility in such cases, as discussed further below.

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

During the year ended December 31, 2019, the actual low, high and average VaR was $0.3 million, $4.3 million and $1.3 million, respectively.

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

Future Realization. As of December 31, 2019, the total estimated future realization of the value of our trading portfolio is expected to occur over 2020 and 2021.

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

Credit and Nonperformance Risk

The fair values of our derivative instruments utilized for corporate hedging and coal trading activities reflect adjustments for credit risk, as necessary. Our exposure is substantially with electric utilities, energy marketers, steel producers and nonfinancial trading houses. Our policy is to independently evaluate each counterparty’s creditworthiness prior to entering into transactions and to regularly monitor exposures. We manage our counterparty risk from our hedging activities related to foreign currency and fuel exposures, as applicable, through established credit standards, diversification of counterparties, utilization of investment grade commercial banks, adherence to established tenor limits based on counterparty creditworthiness and continual monitoring of that creditworthiness. If we engage in a transaction with a counterparty that does not meet our credit standards, we seek to protect our position by requiring the counterparty to provide an appropriate credit enhancement. Also, when appropriate (as determined by our credit management function), we have taken steps to reduce our exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral (margin), requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of a failure to pay or perform. To reduce our credit exposure related to trading and brokerage activities, we seek to enter into netting agreements with counterparties that permit us to offset asset and liability positions with such counterparties and, to the extent required, we will post or receive margin amounts associated with exchange-cleared and certain OTC positions. We also continually monitor counterparty and contract nonperformance risk, if present, on a case-by-case basis.

Foreign Currency Risk

We have historically utilized currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures. The accounting for these derivatives is discussed in Note 9. “Derivatives and Fair Value Measurements” to the accompanying consolidated financial statements. As of December 31, 2019, we had currency options outstanding with an aggregate notional amount of $925.0 million Australian dollars to hedge currency risk associated with anticipated Australian dollar expenditures during the first nine months of 2020. Assuming we had no foreign currency hedging instruments in place, our exposure in operating costs and expenses due to a $0.05 change in the Australian dollar/U.S. dollar exchange rate is approximately $75 to $80 million for the next twelve months. Based upon the Australian dollar/U.S. dollar exchange rate at December 31, 2019, the currency option contracts outstanding at that date would not materially limit our net exposure to a $0.05 unfavorable change in the exchange rate for the next twelve months.

Other Non-Coal Trading Activities — Commodity Price Risk

Long-Term Coal Contracts. We predominantly manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements (those with terms longer than one year) to the extent possible, rather than through the use of derivative instruments. Sales under such agreements comprised approximately 88%, 87% and 83% of our worldwide sales (by volume) for the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019, we had approximately 116 million tons of U.S. thermal coal priced and committed for 2020. This includes approximately 96 million tons of PRB coal and 20 million tons of other U.S. thermal coal. We have the flexibility to increase volumes should demand warrant. We are estimating 2020 thermal coal sales volumes from our Seaborne Thermal Mining segment of 19.2 million tons comprised of thermal export volume of 11.5 million tons and domestic volume of 7.7 million tons. We are estimating full year 2020 metallurgical coal sales from our Seaborne Metallurgical Mining segment of 8.3 million tons. Sales commitments in the metallurgical coal market are typically not long-term in nature, and we are therefore subject to fluctuations in market pricing.

Diesel Fuel Hedges. Previously, we managed price risk of the diesel fuel used in our mining activities through the use of derivatives, primarily swaps. As of December 31, 2019, we did not have any diesel fuel derivative instruments in place. We also manage the price risk of diesel fuel through the use of cost pass-through contacts with certain customers.

We expect to consume 110 to 120 million gallons of diesel fuel during the next twelve months. A $10 per barrel change in the price of crude oil (the primary component of a refined diesel fuel product) would increase or decrease our annual diesel fuel costs by approximately $30 million based on our expected usage.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. From time to time, we manage our debt to achieve a certain ratio of fixed-rate debt and variable-rate debt as a percent of net debt through the use of various hedging instruments. As of December 31, 2019, we had approximately $1 billion of fixed-rate borrowings and $0.4 billion of variable-rate borrowings outstanding and had no interest rate swaps in place. A one percentage point increase in interest rates would result in an annualized increase to interest expense of approximately $4 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a decrease of approximately $29 million in the estimated fair value of these borrowings.

Item 8. *Financial Statements and Supplementary Data.*

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

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

None.

Item 9A. *Controls and Procedures.*

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures are designed to, among other things, provide reasonable assurance that material information, both financial and non-financial, and other information required under the securities laws to be disclosed is accumulated and communicated to senior management, including the principal executive officer and principal accounting officer, on a timely basis. As of December 31, 2019, the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our Chief Executive Officer and Interim Chief Financial Officer have concluded our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act as of December 31, 2019 were effective to provide reasonable assurance that the desired control objectives were achieved.

Changes in Internal Control Over Financial Reporting

We periodically review our internal control over financial reporting as part of our efforts to ensure compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. In addition, we routinely review our system of internal control over financial reporting to identify potential changes to our processes and systems that may improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new systems; consolidating the activities of acquired business units; migrating certain processes to our shared services organizations; formalizing and refining policies, procedures and control documentation requirements; improving segregation of duties and adding monitoring controls. In addition, when we acquire new businesses, we incorporate our controls and procedures into the acquired business as part of our integration activities.

There have been no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. An evaluation of the effectiveness of the design and operation of our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act, as of the end of the period covered by this report was performed under the supervision and with the participation of management, including our Chief Executive Officer and Interim Chief Financial Officer. This evaluation is performed to determine if our internal controls over financial reporting provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework (2013).* Based on this assessment, management concluded that the Company's internal control over financial reporting was effective to provide reasonable assurance that the desired control objectives were achieved as of December 31, 2019.

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

/s/ Glenn L. Kellow	/s/ Mark A. Spurbeck
Glenn L. Kellow *President and Chief Executive Officer*	Mark A. Spurbeck *Interim Chief Financial Officer*

February 21, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Peabody Energy Corporation

Opinion on Internal Control over Financial Reporting

We have audited Peabody Energy Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Peabody Energy Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Peabody Energy Corporation as of December 31, 2019 and 2018 (Successor), the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity and cash flows for the year ended December 31, 2019 and 2018 (Successor), the period from April 2, 2017 through December 31, 2017 (Successor), the period from January 1, 2017 through April 1, 2017 (Predecessor), and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements") of the Company, and our report dated February 21, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Ernst & Young LLP

St. Louis, Missouri

February 21, 2020

Item 9B. *Other Information.*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by Item 401 of Regulation S-K is included under the caption Proposal I - "Election of Directors" in our 2020 Proxy Statement and in Part I, Item 1. "Business" of this report under the caption "Information About Our Executive Officers." The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions "Stock Ownership," "Corporate Governance - Code of Business Conduct and Ethics" and "Additional Information Concerning the Board of Directors - Committee Overview - Audit Committee" in our 2020 Proxy Statement. Such information is incorporated herein by reference.

Item 11. *Executive Compensation.*

The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K is included under the captions "Additional Information Concerning the Board of Directors - Director Compensation," "Compensation Discussion and Analysis," "Compensation Committee Interlocks and Insider Participation" and "Compensation Committee Report" in our 2020 Proxy Statement and is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information required by Item 403 of Regulation S-K is included under the caption "Stock Ownership - Security Ownership of Directors and Management and Certain Beneficial Owners" in our 2020 Proxy Statement and is incorporated herein by reference.

Equity Compensation Plan Information

As required by Item 201(d) of Regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2019:

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights		Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights		Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	551,424	(1)	$ —	(2)	8,877,949
Equity compensation plans not approved by security holders	—		—		—
Total	551,424		$ —		8,877,949

(1) Shares issuable pursuant to outstanding performance units and vested but not issued deferred stock units. Performance units are shown at target and could change based on actual metrics achieved.

(2) The weighted-average exercise price shown in the table does not take into account outstanding deferred stock units or performance awards.

Refer to Note 20. "Share-Based Compensation" to the accompanying consolidated financial statements for additional information regarding the material features of our current equity compensation plans.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions "Review of Related Person Transactions" and "Additional Information Concerning the Board of Directors - Board Independence" in our 2020 Proxy Statement and is incorporated herein by reference.

Item 14. *Principal Accountant Fees and Services.*

The information required by Item 9(e) of Schedule 14A is included under the caption “Audit Fees” in our 2020 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) Documents Filed as Part of the Report

(1) Financial Statements.

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

(2) Financial Statement Schedules.

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

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

(3) Exhibits.

See Exhibit Index hereto.

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

Item 16. *Form 10-K Summary.*

Not applicable.

SIGNATURES

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

PEABODY ENERGY CORPORATION

/s/ GLENN L. KELLOW

Glenn L. Kellow
President and Chief Executive Officer

Date: February 21, 2020

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

Signature	Title	Date
/s/ GLENN L. KELLOW Glenn L. Kellow	President and Chief Executive Officer, Director (principal executive officer)	February 21, 2020
/s/ MARK A. SPURBECK Mark A. Spurbeck	Interim Chief Financial Officer (principal financial and accounting officer)	February 21, 2020
/s/ SAMANTHA ALGAZE Samantha Algaze	Director	February 21, 2020
/s/ ANDREA BERTONE Andrea Bertone	Director	February 21, 2020
/s/ NICHOLAS CHIREKOS Nicholas Chirekos	Director	February 21, 2020
/s/ STEPHEN GORMAN Stephen Gorman	Director	February 21, 2020
/s/ JOE LAYMON Joe Laymon	Director	February 21, 2020
/s/ TERESA MADDEN Teresa Madden	Director	February 21, 2020
/s/ ROBERT MALONE Robert Malone	Chairman	February 21, 2020
/s/ DAVID MILLER David Miller	Director	February 21, 2020
/s/ KENNETH MOORE Kenneth Moore	Director	February 21, 2020
/s/ MICHAEL SUTHERLIN Michael Sutherlin	Director	February 21, 2020
/s/ DARREN YEATES Darren Yeates	Director	February 21, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Peabody Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation (the Company) as of December 31, 2019 and 2018 (Successor), the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity and cash flows for the year ended December 31, 2019 and 2018 (Successor), the period from April 2, 2017 through December 31, 2017 (Successor), and the period from January 1, 2017 through April 1, 2017 (Predecessor), and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2019 and 2018 (Successor), and the results of its operations and its cash flows for the year ended December 31, 2019 and 2018 (Successor), the period from April 2, 2017 through December 31, 2017 (Successor), and the period from January 1, 2017 through April 1, 2017 (Predecessor) in conformity with US generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 21, 2020 expressed an unqualified opinion thereon.

Company Reorganization

As discussed in Notes 1 and 2 to the consolidated financial statements, on March 17, 2017, the Bankruptcy Court entered an order confirming the plan of reorganization, which became effective on April 3, 2017. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, for the Successor Company as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods (Predecessor) as described in Notes 1 and 2.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

Asset Retirement Obligation Liability

Description of the Matter

At December 31, 2019, the Company's asset retirement obligation (ARO) liabilities totaled $752.3 million. As discussed in Note 1 and Note 16 of the consolidated financial statements, the Company estimates its ARO liabilities in the U.S. and Australia for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. The Company records an ARO asset associated with the discounted liability for final reclamation and mine closure and are recognized in the period in which the liability is incurred. As changes in estimates occur, the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate.

Management's estimate involves a high degree of subjectivity and auditing the significant assumptions utilized by management in estimating the amount of the liability requires judgment. In particular, the obligation is determined using a discounted cash flow technique and is based upon mining permit requirements and various assumptions including credit-adjusted risk-free rates, inflation rates, estimates of disturbed acreage, timing of reclamation activities, and reclamation costs.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of the controls over the Company's accounting for ARO liabilities, including controls over management's review of the ARO calculation and the significant assumptions and data inputs described above.

To audit the ARO liabilities, our procedures included evaluating the methodology used, and testing the significant assumptions discussed above and the underlying data used by the Company in its estimate. We compared assumptions including the credit-adjusted risk-free rate, and inflation rate to current market data. In addition, to assess the estimates of disturbed acreage, timing of reclamation activities, and reclamation costs, we evaluated significant changes from the prior estimate, verified consistency between timing of reclamation activities and projected mine life, considered the appropriateness of the estimated costs based on mine type, compared anticipated costs to recent operating data, and recalculated management's estimate. Additionally, we involved our specialists to assist in our assessment of the Company's ARO liability. As part of this effort, our specialists observed mine site operations, interviewed members of the Company's engineering staff, assessed the completeness of the mine reclamation estimate with respect to meeting mine closure and post closure plan regulatory requirements, and evaluated the reasonableness of the engineering estimates and assumptions.

Acquisition of Shoal Creek Mine

Description of the Matter

On December 3, 2018, the Company completed the acquisition of the Shoal Creek metallurgical coal mine, preparation plant and supporting assets located in Alabama (Shoal Creek Mine) for a purchase price of $389.9 million, as disclosed in Note 3 to the consolidated financial statements. The transaction was accounted for as a business combination.

Auditing the Company's accounting for its acquisition of the Shoal Creek Mine was complex due to the significant estimation uncertainty in the Company's determination of the fair value of the identified assets which principally consisted of property, plant, equipment and mine development assets. The significant estimation uncertainty was primarily due to the sensitivity of the respective fair values to underlying assumptions about the future performance of the acquired business and finalizing the life of mine estimates relative to the remaining life and value of specific acquired assets. The Company measured the fair value of the property, plant, equipment and mine development assets using significant assumptions, including discount rates and certain assumptions that form the basis of the forecasted results (e.g., future coal prices and yield of salable tons from the acquired reserves). These significant assumptions are forward looking and could be affected by future market and geological conditions.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Company's acquisition processes. This included controls over the estimates to support the measurement of property, plant, equipment; mine development assets; and consideration transferred in the acquisition. We also tested controls over management's review of assumptions used in the valuation models.

To test the estimated fair value of the assets acquired, we performed audit procedures that included, among others, evaluating the Company's selection of the valuation methodology, evaluating the methods and significant assumptions used in the valuation model, and evaluating the completeness and accuracy of the underlying data supporting the significant assumptions and estimates. We involved our specialists to assist with our evaluation of the methodology used by the Company and significant assumptions included in the fair value estimates. Specifically, when assessing the key assumptions, we evaluated the effect of future coal prices, the yield of salable tons from the acquired reserves, and the impact the life of mine has on the useful life and value of certain acquired assets including rationalization adjustments in order to reconcile the aggregate fair value of the assets acquired to the amount of consideration transferred. In addition, we performed a sensitivity analysis of the significant assumptions to evaluate the change in the fair value estimate that would result from changes in the assumptions and recalculated management's estimate.

Asset Impairment

Description of the Matter	As discussed in Note 5 to the consolidated financial statements, during 2019, the Company recorded an impairment loss on certain long-lived assets related to its El Segundo/Lee Ranch Mine based upon the expectation of reduced sales volumes and uncertainty over remaining economic mine lives. Accordingly, during the fourth quarter, the Company evaluated its long-lived assets for recoverability and determined that these assets were not recoverable and were impaired. As a result, the Company recognized a $172.0 million impairment loss, which is the amount by which the carrying value exceeded the estimated fair value of these assets. Auditing the Company's impairment measurement involved a high degree of subjectivity as estimates underlying the determination of fair value were based on assumptions about future market and economic conditions. Significant assumptions used in the Company’s fair value estimate included coal price forecasts, future volume, future production costs, and the cost of capital.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Company's processes to determine the fair value of the asset group and to measure the long-lived asset impairment. This included controls over management's review of the significant assumptions underlying the fair value determination. Our testing of the Company's impairment measurement included, among other procedures, evaluating the significant assumptions and operating data used to estimate fair value. For example, we compared the significant assumptions used to estimate market participant cash flows to current industry and economic outlook, obtained support to evaluate projected operating data, performed a sensitivity analysis of the significant assumptions to evaluate the change in the fair value estimate that would result from changes in the assumptions and recalculated management's estimate. We also involved our specialists to assist in our evaluation of the cost of capital used in the fair value estimate.

/s/ Ernst & Young, LLP

We have served as the Company’s auditor since 1991.

St. Louis, Missouri

February 21, 2020

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions, except per share data)			
Revenues	$ 4,623.4	$ 5,581.8	$ 4,252.6	$ 1,326.2
Costs and expenses				
Operating costs and expenses (exclusive of items shown separately below)	3,536.6	4,071.4	3,045.1	950.2
Depreciation, depletion and amortization	601.0	679.0	521.6	119.9
Asset retirement obligation expenses	58.4	53.0	41.2	14.6
Selling and administrative expenses	145.0	158.1	106.3	36.3
Restructuring charges	24.3	1.2	7.6	—
Transaction costs related to business combinations and joint ventures	21.6	7.4	—	—
Other operating (income) loss:				
Net gain on disposals	(2.1)	(48.2)	(84.0)	(22.8)
Gain on formation of United Wambo Joint Venture	(48.1)	—	—	—
Asset impairment	270.2	—	—	30.5
Provision for North Goonyella equipment loss	83.2	66.4	—	—
North Goonyella insurance recovery	(125.0)	—	—	—
Income from equity affiliates	(3.4)	(68.1)	(49.0)	(15.0)
Operating profit	61.7	661.6	663.8	212.5
Interest expense	144.0	149.3	119.7	32.9
Loss on early debt extinguishment	0.2	2.0	20.9	—
Interest income	(27.0)	(33.6)	(5.6)	(2.7)
Net periodic benefit costs, excluding service cost	19.4	18.1	21.9	14.4
Net mark-to-market adjustment on actuarially determined liabilities	67.4	(125.5)	(45.2)	—
Reorganization items, net	—	(12.8)	—	627.2
(Loss) income from continuing operations before income taxes	(142.3)	664.1	552.1	(459.3)
Income tax provision (benefit)	46.0	18.4	(161.0)	(263.8)
(Loss) income from continuing operations, net of income taxes	(188.3)	645.7	713.1	(195.5)
Income (loss) from discontinued operations, net of income taxes	3.2	18.1	(19.8)	(16.2)
Net (loss) income	(185.1)	663.8	693.3	(211.7)
Less: Series A Convertible Preferred Stock dividends	—	102.5	179.5	—
Less: Net income attributable to noncontrolling interests	26.2	16.9	15.2	4.8
Net (loss) income attributable to common stockholders	$ (211.3)	$ 544.4	$ 498.6	$ (216.5)
(Loss) income from continuing operations:				
Basic (loss) income per share	$ (2.07)	$ 4.35	$ 3.85	$ (10.93)
Diluted (loss) income per share	$ (2.07)	$ 4.28	$ 3.81	$ (10.93)
Net (loss) income attributable to common stockholders:				
Basic (loss) income per share	$ (2.04)	$ 4.50	$ 3.70	$ (11.81)
Diluted (loss) income per share	$ (2.04)	$ 4.43	$ 3.67	$ (11.81)

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Net (loss) income	$ (185.1)	$ 663.8	$ 693.3	$ (211.7)
Reclassification for realized losses on cash flow hedges (net of respective net tax provision of $0.0, $0.0, $0.0, and $9.1) included in net (loss) income	—	—	—	18.6
Postretirement plans and workers' compensation obligations (net of respective net tax provision of $0.0, $7.1, $0.0, and $2.5)	(8.7)	44.6	—	4.4
Foreign currency translation adjustment	0.2	(5.9)	1.4	5.5
Other comprehensive (loss) income, net of income taxes	(8.5)	38.7	1.4	28.5
Comprehensive (loss) income	(193.6)	702.5	694.7	(183.2)
Less: Series A Convertible Preferred Stock dividends	—	102.5	179.5	—
Less: Net income attributable to noncontrolling interests	26.2	16.9	15.2	4.8
Comprehensive (loss) income attributable to common stockholders	$ (219.8)	$ 583.1	$ 500.0	$ (188.0)

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(Amounts in millions, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 732.2	$ 981.9
Accounts receivable, net of allowance for doubtful accounts of $0.0 at December 31, 2019 and $4.4 at December 31, 2018	329.5	450.4
Inventories	331.5	280.2
Other current assets	220.7	243.1
Total current assets	1,613.9	1,955.6
Property, plant, equipment and mine development, net	4,679.1	5,207.0
Operating lease right-of-use assets	82.4	—
Investments and other assets	139.1	212.6
Deferred income taxes	28.3	48.5
Total assets	$ 6,542.8	$ 7,423.7
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 18.3	$ 36.5
Accounts payable and accrued expenses	957.0	1,022.0
Total current liabilities	975.3	1,058.5
Long-term debt, less current portion	1,292.5	1,330.5
Deferred income taxes	28.8	9.7
Asset retirement obligations	654.1	686.4
Accrued postretirement benefit costs	593.4	547.7
Operating lease liabilities, less current portion	52.8	—
Other noncurrent liabilities	273.4	339.3
Total liabilities	3,870.3	3,972.1
Stockholders' equity		
Preferred Stock — $0.01 per share par value; 100.0 shares authorized, no shares issued or outstanding as of December 31, 2019 or December 31, 2018	—	—
Series Common Stock — $0.01 per share par value; 50.0 shares authorized, no shares issued or outstanding as of December 31, 2019 or December 31, 2018	—	—
Common Stock — $0.01 per share par value; 450.0 shares authorized, 139.2 shares issued and 96.9 shares outstanding as of December 31, 2019 and 137.7 shares issued and 110.4 shares outstanding as of December 31, 2018	1.4	1.4
Additional paid-in capital	3,351.1	3,304.7
Treasury stock, at cost — 42.3 and 27.3 common shares as of December 31, 2019 and December 31, 2018	(1,367.3)	(1,025.1)
Retained earnings	597.0	1,074.5
Accumulated other comprehensive income	31.6	40.1
Peabody Energy Corporation stockholders' equity	2,613.8	3,395.6
Noncontrolling interests	58.7	56.0
Total stockholders' equity	2,672.5	3,451.6
Total liabilities and stockholders' equity	$ 6,542.8	$ 7,423.7

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Cash Flows From Operating Activities				
Net (loss) income	$ (185.1)	$ 663.8	$ 693.3	$ (211.7)
(Income) loss from discontinued operations, net of income taxes	(3.2)	(18.1)	19.8	16.2
(Loss) income from continuing operations, net of income taxes	(188.3)	645.7	713.1	(195.5)
Adjustments to reconcile (loss) income from continuing operations, net of income taxes to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	601.0	679.0	521.6	119.9
Fresh start noncash coal inventory revaluation	—	—	67.3	—
Noncash interest expense including loss on early extinguishment of debt	16.2	19.2	34.0	0.5
Deferred income taxes	39.4	35.5	(99.6)	(262.3)
Noncash share-based compensation	38.3	34.9	21.8	1.9
Asset impairment	270.2	—	—	30.5
Net gain on disposals	(2.1)	(48.2)	(84.0)	(22.8)
Income from equity affiliates	(3.4)	(68.1)	(49.0)	(15.0)
Provision for North Goonyella equipment loss	83.2	66.4	—	—
Gain on formation of United Wambo Joint Venture	(48.1)	—	—	—
Foreign currency option contracts	5.2	9.1	(0.8)	—
Reclassification from other comprehensive earnings for terminated hedge contracts	—	—	—	27.6
Noncash reorganization items, net	—	(12.8)	—	(485.4)
Changes in current assets and liabilities:				
Accounts receivable	82.9	171.8	(240.1)	159.3
Inventories	(53.3)	50.2	(36.8)	(47.2)
Other current assets	(35.6)	(30.6)	(53.1)	0.2
Accounts payable and accrued expenses	(118.2)	(160.2)	(158.5)	(65.5)
Collateral arrangements	—	323.1	288.3	(66.4)
Asset retirement obligations	6.6	5.7	12.1	10.2
Workers' compensation obligations	5.0	(1.8)	(1.1)	(3.1)
Postretirement benefit obligations	36.8	(151.1)	(19.8)	0.8
Pension obligations	(32.5)	(66.9)	(55.4)	5.4
Take-or-pay obligation settlement	—	—	—	(5.5)
Other, net	2.1	16.0	(27.8)	7.6
Net cash provided by (used in) continuing operations	705.4	1,516.9	832.2	(804.8)
Net cash used in discontinued operations	(28.0)	(27.2)	(18.8)	(8.2)
Net cash provided by (used in) operating activities	677.4	1,489.7	813.4	(813.0)

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS - (Continued)

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Cash Flows From Investing Activities				
Additions to property, plant, equipment and mine development	(285.4)	(301.0)	(166.6)	(32.8)
Changes in accrued expenses related to capital expenditures	0.1	0.1	16.2	(1.4)
Federal coal lease expenditures	—	(0.5)	—	(0.5)
Insurance proceeds attributable to North Goonyella equipment losses	23.2	—	—	—
Proceeds from disposal of assets, net of receivables	30.0	76.4	17.9	24.3
Amount attributable to acquisition of Shoal Creek Mine	(2.4)	(387.4)	—	—
Contributions to joint ventures	(419.1)	(475.3)	(305.8)	(95.4)
Distributions from joint ventures	408.8	483.7	307.0	90.5
Advances to related parties	(27.3)	(13.8)	(3.0)	(0.4)
Cash receipts from Middlemount Coal Pty Ltd	14.7	106.7	48.1	32.7
Investment in equity securities	(3.0)	(10.0)	—	—
Other, net	(0.9)	3.8	(7.2)	(1.9)
Net cash (used in) provided by investing activities	(261.3)	(517.3)	(93.4)	15.1
Cash Flows From Financing Activities				
Proceeds from long-term debt	—	—	—	1,000.0
Repayments of long-term debt	(71.1)	(85.0)	(541.8)	(2.1)
Payment of debt issuance and other deferred financing costs	(6.4)	(21.2)	(10.8)	(45.4)
Common stock repurchases	(329.9)	(834.7)	(175.7)	—
Repurchase of employee common stock relinquished for tax withholding	(12.3)	(14.5)	(0.2)	(0.1)
Dividends paid	(258.1)	(59.6)	—	—
Distributions to noncontrolling interests	(23.5)	(10.3)	(16.7)	(0.1)
Other, net	—	0.1	(0.2)	—
Net cash (used in) provided by financing activities	(701.3)	(1,025.2)	(745.4)	952.3
Net change in cash, cash equivalents and restricted cash	(285.2)	(52.8)	(25.4)	154.4
Cash, cash equivalents and restricted cash at beginning of period (1)	1,017.4	1,070.2	1,095.6	941.2
Cash, cash equivalents and restricted cash at end of period (2)	$ 732.2	$ 1,017.4	$ 1,070.2	$ 1,095.6

(1) The following table provides a reconciliation of “Cash, cash equivalents and restricted cash at beginning of period”:

Cash and cash equivalents	$ 981.9
Restricted cash included in “Investments and other assets”	35.5
Cash, cash equivalents and restricted cash at beginning of period	$ 1,017.4

(2) The following table provides a reconciliation of “Cash, cash equivalents and restricted cash at end of period”:

Cash and cash equivalents	$ 732.2
Restricted cash included in “Investments and other assets”	—
Cash, cash equivalents and restricted cash at end of period	$ 732.2

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Peabody Energy Corporation Stockholders' Equity							
	Series A Convertible Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	(Accumulated Deficit) Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Stockholders' Equity
	(Dollars in millions)							
December 31, 2016 - Predecessor	$ —	$ 0.2	$ 2,422.0	$ (371.8)	$ (1,399.5)	$ (477.0)	$ 7.6	$ 181.5
Net (loss) income	—	—	—	—	(216.5)	—	4.8	(211.7)
Net realized losses on cash flow hedges (net of $9.1 net tax provision)	—	—	—	—	—	18.6	—	18.6
Postretirement plans and workers' compensation obligations (net of $2.5 tax provision)	—	—	—	—	—	4.4	—	4.4
Foreign currency translation adjustment	—	—	—	—	—	5.5	—	5.5
Share-based compensation for equity-classified awards	—	—	1.9	—	—	—	—	1.9
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(0.1)	—	—	—	(0.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	(0.1)	(0.1)
Elimination of Predecessor equity	—	(0.2)	(2,423.9)	371.9	1,616.0	448.5	(12.3)	—
April 1, 2017 - Predecessor	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Issuance of Successor equity	1,305.4	0.7	1,774.9	—	—	—	50.9	3,131.9
April 2, 2017 - Successor	$ 1,305.4	$ 0.7	$ 1,774.9	$ —	$ —	$ —	$ 50.9	$ 3,131.9
Net income	—	—	—	—	678.1	—	15.2	693.3
Foreign currency translation adjustment	—	—	—	—	—	1.4	—	1.4
Warrant conversions	—	0.1	(0.1)	—	—	—	—	—
Series A Convertible Preferred Stock conversions	(748.2)	0.2	796.7	—	(48.7)	—	—	—
Series A Convertible Preferred Stock dividends	18.8	—	(3.0)	—	(15.8)	—	—	—
Share-based compensation for equity-classified awards	—	—	21.8	—	—	—	—	21.8
Common stock repurchases	—	—	—	(175.7)	—	—	—	(175.7)
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(0.2)	—	—	—	(0.2)
Distributions to noncontrolling interests	—	—	—	—	—	—	(16.7)	(16.7)
December 31, 2017 - Successor	$ 576.0	$ 1.0	$ 2,590.3	$ (175.9)	$ 613.6	$ 1.4	$ 49.4	$ 3,655.8
Impact of adoption of Accounting Standards Update 2014-09	—	—	—	—	(22.5)	—	—	(22.5)
Net income	—	—	—	—	646.9	—	16.9	663.8
Dividends declared ($0.485 per share)	—	—	1.4	—	(61.0)	—	—	(59.6)
Postretirement plans and workers' compensation obligations (net of $7.1 tax provision)	—	—	—	—	—	44.6	—	44.6
Foreign currency translation adjustment	—	—	—	—	—	(5.9)	—	(5.9)
Series A Convertible Preferred Stock conversions	(576.0)	0.4	678.1	—	(102.5)	—	—	—
Share-based compensation for equity-classified awards	—	—	34.9	—	—	—	—	34.9
Common stock repurchases	—	—	—	(834.7)	—	—	—	(834.7)
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(14.5)	—	—	—	(14.5)
Distributions to noncontrolling interests	—	—	—	—	—	—	(10.3)	(10.3)
December 31, 2018 - Successor	$ —	$ 1.4	$ 3,304.7	$ (1,025.1)	$ 1,074.5	$ 40.1	$ 56.0	$ 3,451.6
Net (loss) income	—	—	—	—	(211.3)	—	26.2	(185.1)
Dividends declared ($2.410 per share)	—	—	8.1	—	(266.2)	—	—	(258.1)
Postretirement plans and workers' compensation obligations (net of $0.0 tax provision)	—	—	—	—	—	(8.7)	—	(8.7)
Foreign currency translation adjustment	—	—	—	—	—	0.2	—	0.2
Share-based compensation for equity-classified awards	—	—	38.3	—	—	—	—	38.3
Common stock repurchases	—	—	—	(329.9)	—	—	—	(329.9)
Repurchase of employee common stock relinquished for tax withholding	—	—	—	(12.3)	—	—	—	(12.3)
Distributions to noncontrolling interests	—	—	—	—	—	—	(23.5)	(23.5)
December 31, 2019 - Successor	$ —	$ 1.4	$ 3,351.1	$ (1,367.3)	$ 597.0	$ 31.6	$ 58.7	$ 2,672.5

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (PEC) and its affiliates. The Company, or Peabody, are used interchangeably to refer to Peabody Energy Corporation, to Peabody Energy Corporation and its subsidiaries, or to such subsidiaries, as appropriate to the context. Interests in subsidiaries controlled by the Company are consolidated with any outside stockholder interests reflected as noncontrolling interests, except when the Company has an undivided interest in an unincorporated joint venture. In those cases, the Company includes its proportionate share in the assets, liabilities, revenues and expenses of the jointly controlled entities within each applicable line item of the consolidated financial statements. All intercompany transactions, profits and balances have been eliminated in consolidation.

Description of Business

The Company is engaged in the mining of thermal coal for sale primarily to electric utilities and metallurgical coal for sale to industrial customers. The Company's mining operations are located in the United States (U.S.) and Australia, including an equity-affiliate mining operation in Australia. The Company also markets and brokers coal from other coal producers and trades coal and freight-related contracts through trading and business offices in the U.S., Australia, China and the United Kingdom. The Company's other commercial activities include managing its coal reserve and real estate holdings, and supporting the development of clean coal technologies.

Plan of Reorganization and Emergence from Chapter 11 Cases

On April 13, 2016, PEC and a majority of its wholly owned domestic subsidiaries, as well as one international subsidiary in Gibraltar (collectively with PEC, the Debtors), filed voluntary petitions (the Bankruptcy Petitions) under Chapter 11 of Title 11 of the U.S. Code (the Bankruptcy Code) in the U.S. Bankruptcy Court for the Eastern District of Missouri (the Bankruptcy Court). The Debtors' Chapter 11 cases (the Chapter 11 Cases) were jointly administered under the caption *In re Peabody Energy Corporation, et al.*, Case No. 16-42529.

For periods subsequent to filing the Bankruptcy Petitions, the Company applied the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852, "Reorganizations," in preparing its consolidated financial statements. ASC 852 requires that financial statements distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that were realized or incurred in the bankruptcy proceedings were recorded in "Reorganization items, net" in the consolidated statements of operations.

On March 17, 2017, the Bankruptcy Court entered an order, Docket No. 2763, confirming the Debtors' Second Amended Joint Plan of Reorganization of Debtors and Debtors in Possession (as further modified, the Plan). On April 3, 2017, (the Effective Date), the Debtors satisfied the conditions to effectiveness set forth in the Plan, the Plan became effective in accordance with its terms and the Debtors emerged from the Chapter 11 Cases.

On the Effective Date, in accordance with ASC 852, the Company applied fresh start reporting which requires the Company to allocate its reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. The Company was permitted to use fresh start reporting because (i) the holders of existing voting shares of the Predecessor (as defined below) company received less than 50% of the voting shares of the emerging entity upon reorganization and (ii) the reorganization value of the Company's assets immediately prior to Plan confirmation was less than the total of all postpetition liabilities and allowed claims.

Upon adoption of fresh start reporting, the Company became a new entity for financial reporting purposes, reflecting the Successor (as defined below) capital structure. As a result, a new accounting basis in the identifiable assets and liabilities assumed was established with no retained earnings or accumulated other comprehensive income (loss) for financial reporting purposes. The Company selected an accounting convenience date of April 1, 2017 for purposes of applying fresh start reporting as the activity between the convenience date and the Effective Date did not result in a material difference in the results. References to “Successor” in the financial statements and accompanying footnotes are in reference to reporting dates on or after April 2, 2017; references to “Predecessor” in the financial statements and accompanying footnotes are in reference to reporting dates through April 1, 2017 which includes the impact of the Plan provisions and the application of fresh start reporting. As such, the Company’s financial statements for the Successor will not be comparable in many respects to its financial statements for periods prior to the adoption of fresh start reporting and prior to the accounting for the effects of the Plan.

In connection with fresh start reporting, the Company made certain prospective accounting policy elections that impact the Successor periods presented herein. The Company now classifies the amortization associated with its asset retirement obligation assets within “Depreciation, depletion and amortization” in its consolidated statements of operations, rather than within “Asset retirement obligation expenses,” as in Predecessor periods. With respect to its accrued postretirement benefit and pension obligations, the Company now records amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over the applicable time periods.

Newly Adopted Accounting Standards

Leases. In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02, “Leases (Topic 842),” to increase transparency and comparability among organizations by requiring the recognition of right-of-use (ROU) assets and lease liabilities on the balance sheet for leases with lease terms of more than 12 months. Most prominent among the changes in the standard is the recognition of ROU assets and lease liabilities by lessees for those leases classified as operating leases. The FASB continued to clarify this guidance through the issuance of additional updates to ASU 2016-02.

On January 1, 2019, the Company adopted ASU 2016-02 using the modified transition approach and elected the package of practical expedients offered under ASU 2016-02, as updated, that allows it to forgo reassessment of lease classification for leases that have already commenced. The Company also elected the practical expedients to adopt ASU 2016-02 without restating comparative prior period financial information, to not recognize ROU assets and lease liabilities for operating leases with shorter than 12-month terms and to include both lease and non-lease components within lease payments. The Company has implemented the systems functionality and internal control processes necessary to comply with the new reporting requirements of ASU 2016-02.

The Company recognized the cumulative effect of initially applying ASU 2016-02 as an adjustment on January 1, 2019 and comparative information presented herein has not been restated. ASU 2016-02 had a material impact on the Company's consolidated balance sheet but did not have a material impact on its results of operations or its cash flows. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases upon adoption, as set forth in the table below. The Company's accounting for finance leases remained unchanged.

	Adoption of ASU 2016-02 January 1, 2019
	(Dollars in millions)
ASSETS	
Operating lease right-of-use assets	$ 109.3
Total assets	$ 109.3
LIABILITIES	
Accounts payable and accrued expenses	$ 41.8
Total current liabilities	41.8
Operating lease liabilities, less current portion	67.5
Total liabilities	$ 109.3

ASU 2016-02 also requires entities to disclose certain qualitative and quantitative information regarding the amount, timing and uncertainty of cash flows arising from leases. Such disclosures are included in Note 15. “Leases.”

Leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible rights to explore for those natural resources and rights to use the land in which those natural resources are contained are excluded from the scope of ASU 2016-02. As such, the adoption of ASU 2016-02 did not impact the accounting for the coal reserve leases under which the Company mines a substantial amount of its coal production. Such leases typically require royalties to be paid as the coal is mined and sometimes require minimum annual royalties to be paid regardless of the amount of coal mined during the year.

Leases - Land Easements. In January 2018, the FASB issued ASU 2018-01 to provide an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under prior leasing guidance. On January 1, 2019, the Company adopted the expedient to evaluate new or modified land easements under Topic 842, and it did not have a material impact on the Company's results of operations, financial condition, cash flows or financial statement presentation.

Accounting Standards Not Yet Implemented

Financial Instruments - Credit Losses. In June 2016, the FASB issued ASU 2016-13 related to the measurement of credit losses on financial instruments. The new standard replaces the incurred loss methodology to record credit losses with a methodology that reflects the expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. The Company will be required to use a forward-looking expected loss model for accounts receivables, loans and other financial instruments to record an allowance for the estimated contractual cash flows not expected to be collected. This standard is effective for fiscal years beginning after December 15, 2019 (January 1, 2020 for the Company) and interim periods therein, with early adoption permitted. Adoption of the standard will be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the effective date to align the Company's credit loss methodology with the new standard. The Company adopted the standard on January 1, 2020 with no material impact to the Company's results of operations, financial condition, cash flows or financial statement presentation.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13, which amended the fair value measurement guidance by removing and modifying certain disclosure requirements, while also adding new disclosure requirements. The amendments on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements and the narrative description of measurement uncertainty should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption. All other amendments should be applied retrospectively to all periods presented upon their effective date. The amendments are effective for all companies for fiscal years, and interim periods within those years, beginning after December 15, 2019. The Company plans to adopt all disclosure requirements effective January 1, 2020.

Compensation- Retirement Benefits. In August 2018, the FASB issued ASU 2018-14 to add, remove and clarify disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. ASU 2018-14 is effective for fiscal years ending after December 15, 2020 for public companies and early adoption is permitted. The Company plans to adopt the disclosure requirements effective January 1, 2020.

Income Taxes. In December 2019, the FASB issued ASU 2019-12 as part of its effort to reduce the complexity of accounting standards. The ASU enhances and simplifies various aspects of the income tax accounting guidance in ASC 740, including requirements related to (1) hybrid tax regimes, (2) the tax basis step-up in goodwill obtained in a transaction that is not a business combination, (3) separate financial statements of entities not subject to tax, (4) the intraperiod tax allocation exception to the incremental approach, (5) recognition of a deferred tax liability after an investor in a foreign entity transitions to or from the equity method of accounting, (6) interim-period accounting for enacted changes in tax law and (7) the year-to-date loss limitation in interim-period tax accounting. ASU 2019-12 is effective on January 1, 2021 for calendar year-end public companies and early adoption is permitted. The Company plans to adopt the requirements effective January 1, 2021.

Revenues

The majority of the Company's revenue is derived from the sale of coal 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) and contracts with terms of less than one year, including sales made on a spot basis. The Company's revenue from coal sales is realized and earned when control passes to the customer. Under the typical terms of the Company's coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the transportation sources that serve the Company's mines. The Company incurs certain "add-on" taxes and fees on coal sales. Reported coal sales include taxes and fees charged by various federal and state governmental bodies and the freight charged on destination customer contracts.

The Company’s seaborne operating platform is primarily export focused with customers spread across several countries, with a portion of the thermal and metallurgical coal 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. A majority of these sales are executed through annual and multi-year international coal supply agreements that contain provisions requiring both parties to renegotiate pricing periodically. Industry commercial practice, and the Company’s typical practice, is to negotiate pricing for seaborne thermal coal contracts on an annual, spot or index basis and seaborne metallurgical coal contracts on a quarterly, spot or index basis. The portion of sales volume under contracts with a duration of less than one year has increased in recent years. In the case of periodically negotiated pricing, the Company may deliver coal under provisional pricing until a final agreed-upon price is determined. The resulting make-whole settlements are recognized when reasonably estimable.

The Company’s U.S. thermal operating platform primarily sells thermal coal to electric utilities in the U.S. under long-term contracts, with a portion sold into the seaborne markets as conditions warrant. A significant portion of the coal production from the U.S. thermal mining segments is sold 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 may vary 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.

Contract pricing is set forth on a per ton basis, and revenue is generally recorded as the product of price and volume delivered. Many of the Company’s coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. These contract prices may be adjusted 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. The Company sometimes experiences a reduction in coal prices in new long-term coal supply agreements replacing some of its expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by the Company or the customer during the duration of specified events beyond the control of the affected party. Most of the coal supply agreements contain provisions requiring the Company 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 the Company’s customers to terminate their contracts in the event of changes in regulations affecting the industry that restrict the use or type of coal permissible at the customer’s plant or increase the price of coal beyond specified limits.

Additional revenues may include gains and losses related to mark-to-market adjustments from economic hedge activities intended to hedge future coal sales, revenues from customer contract-related payments and other insignificant items including royalties related to coal lease agreements, sales agency commissions, farm income and property and facility rentals. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced.

Discontinued Operations

The Company classifies items within discontinued operations in the consolidated financial statements when the operations and cash flows of a particular component of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal (by sale or otherwise) and represents a strategic shift that has (or will have) a major effect on the entity’s operations and financial results. Refer to Note 6. “Discontinued Operations” for additional details related to discontinued operations.

Assets and Liabilities Held for Sale

The Company classifies assets and liabilities (disposal groups) to be sold as held for sale in the period in which all of the following criteria are met: management, having the authority to approve the action, commits to a plan to sell the disposal group; the disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such disposal groups; an active program to locate a buyer and other actions required to complete the plan to sell the disposal group have been initiated; the sale of the disposal group is probable, and transfer of the disposal group is expected to qualify for recognition as a completed sale within one year, except if events or circumstances beyond the Company's control extend the period of time required to sell the disposal group beyond one year; the disposal group is being actively marketed for sale at a price that is reasonable in relation to its current fair value; and actions required to complete the plan indicate that it is unlikely that significant changes to the plan will be made or that the plan will be withdrawn.

The Company initially measures a disposal group that is classified as held for sale at the lower of its carrying value or fair value less any costs to sell. Any loss resulting from this measurement is recognized in the period in which the held for sale criteria are met. Conversely, gains are not recognized on the sale of a disposal group until the date of sale. The Company assesses the fair value of a disposal group, less any costs to sell, each reporting period it remains classified as held for sale and reports any subsequent changes as an adjustment to the carrying value of the disposal group, as long as the new carrying value does not exceed the carrying value of the disposal group at the time it was initially classified as held for sale.

Upon determining that a disposal group meets the criteria to be classified as held for sale, the Company reports the assets and liabilities of the disposal group, if material, in the line items assets held for sale and liabilities held for sale in the consolidated balance sheets.

Cash and Cash Equivalents

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

Accounts Receivable

The timing of revenue recognition, billings and cash collections results in accounts receivable from customers. Customers are invoiced as coal is shipped or at periodic intervals in accordance with contractual terms. Invoices typically include customary adjustments for the resolution of price variability related to prior shipments, such as coal quality thresholds. Payments are generally received within thirty days of invoicing.

Inventories

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

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

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

Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. There was no capitalized interest in any of the periods presented. Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Maintenance and repair costs incurred to maintain current production capacity at a mine are charged to operating costs as incurred. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.

Coal reserves are recorded at cost, or at fair value in the case of nonmonetary exchanges of reserves or business acquisitions.

Depletion of coal reserves and amortization of advance royalties are computed using the units-of-production method utilizing only proven and probable reserves (as adjusted for recoverability factors) in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method. Depreciation of plant and equipment is computed using the straight-line method over the shorter of the asset's estimated useful life or the life of the mine. The estimated useful lives by category of assets are as follows:

	Years
Building and improvements	up to 29
Machinery and equipment	1 - 15
Leasehold improvements	Shorter of Useful Life or Remaining Life of Lease

The Company leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $388.6 million, $474.3 million, $364.6 million and $115.2 million for the years ended December 31, 2019 and 2018, and the periods April 2 through December 31, 2017 and January 1 through April 1, 2017, respectively.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from the owner. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Wyoming under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production, by including the lease as a part of a logical mining unit with other leases upon which development has occurred or by paying an advance royalty in lieu of continued operations. Annual production on these federal leases must total at least 1.0% of the leased reserve or the original amount of coal in the entire logical mining unit in which the leased reserve resides. In addition, royalties are payable monthly at a rate of 12.5% of the gross realization from the sale of the coal mined using surface mining methods and at a rate of 8.0% of the gross realization for coal produced using underground mining methods.

The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Mining and exploration in Australia is generally conducted under leases, licenses or permits granted by the relevant state government. Mining and exploration licenses and their associated environmental protection approvals (granted by the state government, and in some cases also the federal government) contain conditions relating to such matters as minimum annual expenditures, environmental compliance, protection of flora and fauna, restoration and rehabilitation. Royalties are paid to the state government as a percentage of the sales price (less certain allowable deductions in some cases). Generally, landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by the state government. Compensation is often payable to landowners, occupiers and Aboriginal traditional owners with residual native title rights and interests for the loss of access to the land from the proposed mining activities. The amount and type of compensation and the ability to proceed to grant of a mining tenement may be determined by agreement or court determination, as provided by law.

Leases

The Company determines if an arrangement is a lease at inception. ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent its obligation to make lease payments arising from the lease. Operating lease ROU assets and liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term. For the purpose of calculating such present values, lease payments include components that vary based upon an index or rate, using the prevailing index or rate at the commencement date, and exclude components that vary based upon other factors. As most of its leases do not contain a readily determinable implicit rate, the Company uses its incremental borrowing rate at commencement to determine the present value of lease payments. Variable lease payments not included within lease contracts are expensed as incurred. The Company's leases may include options to extend or terminate the lease, and such options are reflected in the term when their exercise is reasonably certain. Lease expense is recognized on a straight-line basis over the lease term.

For certain equipment leases, the Company applies a portfolio approach to effectively account for the operating lease ROU assets and liabilities.

Equity Investments

The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost and any difference between the cost of the Company's investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company's pro-rata share of the operating results of joint ventures and basis difference amortization is reported in the consolidated statements of operations in "Income from equity affiliates." Similarly, the Company's pro-rata share of the cumulative foreign currency translation adjustment of its equity method investments whose functional currency is not the U.S. dollar is reported in the consolidated balance sheets as a component of "Accumulated other comprehensive income," with periodic changes thereto reflected in the consolidated statements of comprehensive income.

The Company monitors its equity method investments for indicators that a decrease in investment value has occurred that is other than temporary. Examples of such indicators include a sustained history of operating losses and adverse changes in earnings and cash flow outlook. In the absence of quoted market prices for an investment, discounted cash flow projections are used to assess fair value, the underlying assumptions to which are generally considered unobservable Level 3 inputs under the fair value hierarchy. If the fair value of an investment is determined to be below its carrying value and that loss in fair value is deemed other than temporary, an impairment loss is recognized. No such impairment losses were recorded in any period presented.

For the remaining investments, the Company will adjust the carrying value of its investments to fair value based on observable market transactions. The Company also monitors such investments for indicators of impairment should no observable market transactions exist. Refer to Note 5. "Asset Impairment" for details regarding an impairment loss of $9.0 million recorded during the year ended December 31, 2019 related to an investment in an equity security. No such impairment losses were recorded during the year ended December 31, 2018 or the periods April 2 through December 31, 2017 and January 1 through April 1, 2017.

Asset Retirement Obligations

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

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

Contingent Liabilities

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

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

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

Income Taxes

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

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

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions by accruing the costs of benefits to be provided over the employees’ period of active service. These costs are determined on an actuarial basis. The Company’s consolidated balance sheets reflect the accumulated postretirement benefit obligations of its postretirement benefit plans. The Company accounts for changes in its postretirement benefit obligations as a settlement when an irrevocable action has been effected that relieves the Company of its actuarially-determined liability to individual plan participants and removes substantial risk surrounding the nature, amount and timing of the obligation’s funding and the assets used to effect the settlement. See Note 17. “Postretirement Health Care and Life Insurance Benefits” for information related to postretirement benefits.

Pension Plans

The Company sponsors non-contributory defined benefit pension plans accounted for by accruing the cost to provide the benefits over the employees’ period of active service. These costs are determined on an actuarial basis. The Company’s consolidated balance sheets reflect the funded status of the defined benefit pension plans. See Note 18. “Pension and Savings Plans” for information related to pension plans.

Restructuring Activities

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

Included as a component of “Restructuring charges” in the Company’s consolidated statements of operations for the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017 were aggregate restructuring charges of $24.3 million, $1.2 million and $7.6 million, respectively, primarily associated with voluntary and involuntary workforce reductions. There were no restructuring charges during the period January 1 through April 1, 2017. As of December 31, 2019, a $7.4 million accrual for restructuring charges remained in “Accounts payable and accrued expenses,” which is expected to be paid in the first quarter of 2020.

Derivatives

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

With respect to derivatives used in hedging activities, the Company assesses at hedge inception whether such derivatives are highly effective at offsetting the changes in the anticipated exposure of the hedged item. The change in the fair value of derivatives designated as a cash flow hedge is recorded in “Accumulated other comprehensive income” in the consolidated balance sheets until the hedged transaction impacts reported earnings, at which time any gain or loss is reclassified to earnings. If the hedge ceases to qualify for hedge accounting, the Company prospectively recognizes changes in the fair value of the instrument in earnings in the period of the change. Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in earnings, along with the offsetting gain or loss related to the underlying hedged item.

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

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

Business Combinations

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

Impairment of Long-Lived Assets

The Company evaluates its long-lived assets held and used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition. The Company generally does not view short-term declines in thermal and metallurgical coal prices as a triggering event for conducting impairment tests because of historic price volatility. However, the Company generally does view a sustained trend of depressed coal pricing (for example, over periods exceeding one year) as an indicator of potential impairment. Because of the volatile and cyclical nature of coal prices and demand, it is reasonably possible that coal prices may decrease and/or fail to improve in the near term, which, absent sufficient mitigation such as an offsetting reduction in the Company’s operating costs, may result in the need for future adjustments to the carrying value of the Company’s long-lived mining assets and mining-related investments.

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

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

Refer to Note 5. "Asset Impairment" for details regarding impairment charges related to long-lived assets of $261.2 million and $30.5 million recognized during the year ended December 31, 2019 and the period January 1 through April 1, 2017, respectively. There were no impairment charges related to long-lived assets during the year ended December 31, 2018 or the period April 2 through December 31, 2017.

Fair Value

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

Foreign Currency

Functional currency is determined by the primary economic environment in which an entity operates, which for the Company's foreign operations is generally the U.S. dollar because sales prices in international coal markets and the Company's sources of financing those operations are denominated in that currency. Accordingly, substantially all of the Company's consolidated foreign subsidiaries utilize the U.S. dollar as their functional currency. Monetary assets and liabilities are remeasured at year-end exchange rates while non-monetary items are remeasured at historical rates. Income and expense accounts are remeasured at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement related to tax balances are included as a component of "Income tax provision (benefit)," while all other remeasurement gains and losses are included in "Operating costs and expenses" in the consolidated statements of operations. The total impact of foreign currency remeasurement on the consolidated statements of operations was a net loss of $2.7 million for the year ended December 31, 2019 and a net gain of $1.4 million, $0.7 million and $10.6 million for the year ended December 31, 2018 and the periods April 2 through December 31, 2017 and January 1 through April 1, 2017, respectively.

The Company owns a 50% equity interest in Middlemount Coal Pty Ltd. (Middlemount), which owns the Middlemount Mine in Queensland, Australia. Middlemount utilizes the Australian dollar as its functional currency. Accordingly, the assets and liabilities of that equity investee are translated to U.S. dollars at the year-end exchange rate and income and expense accounts are translated at the average rate in effect during the year. The Company's pro-rata share of the translation gains and losses of the equity investee are recorded as a component of "Accumulated other comprehensive income" in the consolidated balance sheets. Australian dollar denominated stockholder loans to the Middlemount Mine, which are long term in nature, are considered part of the Company's net investment in that operation. Accordingly, foreign currency gains or losses on those loans are recorded as a component of foreign currency translation adjustment. The Company recorded foreign currency translation gains of $0.2 million, $1.4 million and $5.5 million for the year ended December 31, 2019 and the periods April 2 through December 31, 2017 and January 1 through April 1, 2017, respectively, and a loss of $5.9 million for the year ended December 31, 2018.

Share-Based Compensation

The Company accounts for share-based compensation at the grant date fair value of awards and recognizes the related expense over the service period of the awards. See Note 20. "Share-Based Compensation" for information related to share-based compensation.

Exploration and Drilling Costs

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

Advance Stripping Costs

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

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

Use of Estimates in the Preparation of the Consolidated Financial Statements

These consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the U.S. (U.S. GAAP). In doing so, estimates and assumptions are made that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates are based on historical experience and on various other assumptions deemed reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The Company's actual results may differ materially from these estimates. Significant estimates inherent in the preparation of these consolidated financial statements include, but are not limited to, accounting for sales and cost recognition, postretirement benefit plans, environmental receivables and liabilities, asset retirement obligations, evaluation of long-lived assets for impairment, income taxes including deferred tax assets, fair value measurements and contingencies.

(2) Reorganization Items

The Company's application of fresh start reporting resulted in recognition of the following reorganization items for the periods presented below:

	Successor	Predecessor
	Year Ended December 31, 2018	January 1 through April 1, 2017
	(Dollars in millions)	
Gain on settlement of claims	$ (12.8)	$ (3,031.2)
Fresh start adjustments, net	—	3,363.1
Fresh start income tax adjustments, net	—	253.9
Professional fees	—	42.5
Accounts payable settlement gains	—	(0.7)
Interest income	—	(0.4)
Reorganization items, net	$ (12.8)	$ 627.2

Upon implementation of the Plan on the Effective Date, the Company recorded a gain on the settlement of liabilities subject to compromise through a combination of cash payments, the issuance of new common stock and warrants and the issuance of new debt. The following is the calculation of the total pre-tax gain on the settlement of the liabilities subject to compromise.

	(Dollars in millions)
Liabilities subject to compromise	$ 8,416.7
Less amounts issued to settle claims:	
Successor Common Stock (at par)	(0.7)
Successor Series A Convertible Preferred Stock	(1,305.4)
Successor Additional paid-in capital	(1,774.9)
Issuance of Successor Notes	(1,000.0)
Issuance of Successor Term Loan	(950.0)
Cash payments and accruals for claims and professional fees	(336.4)
Other:	
Write-off of Predecessor debt issuance costs	(18.1)
Gain on settlement of claims	$ 3,031.2

At the Effective Date, 70.9 million shares of Common Stock were issued and outstanding at a par value of $0.01 per share. Convertible Preferred Stock was recorded at fair value and was based upon the $750.0 million cash raised upon emergence from bankruptcy through the Private Placement Agreement, plus a premium to account for the fair value of the Convertible Preferred Stocks' conversion and dividend features. Each share of Convertible Preferred Stock was convertible, at the holder's election or upon the occurrence of certain triggering events, into shares of Common Stock at a 35% discount relative to the initial per share purchase price of $25.00 and provided for three years of guaranteed paid-in-kind dividends, payable semiannually, at a rate of 8.5% per annum. The 46.2 million shares of Common Stock issuable upon conversion of the Convertible Preferred Stock issued under the Plan and an additional 13.1 million shares of Common Stock attributable to such Convertible Preferred Stocks' guaranteed paid-in-kind dividend feature constituted approximately 42% ownership of the Plan Equity Value (as defined in the Plan) of $3,105.0 million in the reorganized Company, and thus had a fair value of $1,305.4 million. Successor Additional paid-in capital was recorded at the Plan Equity Value less the amounts recorded for par value of the Common Stock, the fair value of the Convertible Preferred Stock, and certain fees incurred associated with the Registration Rights Agreement.

During the year ended December 31, 2018, the Company recorded an additional gain on the settlement of claims for $12.8 million related to certain unsecured claims.

Upon implementation of the Plan on the Effective Date, the Company recorded fresh start adjustments, net, as follows:

		(Dollars in millions)
Inventories	(a)	$ 70.1
Other current assets	(b)	(333.0)
Property, plant, equipment and mine development, net	(c)	(3,461.4)
Investments and other assets	(d)	238.0
Accounts payable and accrued expenses	(e)	(14.8)
Deferred income taxes	(f)	177.8
Asset retirement obligations	(g)	73.9
Accrued postretirement benefit costs	(h)	6.9
Other noncurrent liabilities	(i)	(120.6)
Total fresh start adjustments, net		$ (3,363.1)

(a) Represents adjustment to increase the book value of coal inventories to their estimated fair value, less costs to sell the inventories.

(b) Represents adjustments comprising $228.5 million related to assets classified as held-for-sale at March 31, 2017 which were reclassified as held-for-use and considered in connection with the valuations described in (c) below,$89.5 million to write off certain existing short-term mine development costs, and $15.0 million of various prepaid assets deemed to have no future utility subsequent to the Effective Date.

(c) Represents a $3,461.4 million reduction in property, plant and equipment to estimated fair value as discussed below:

The fair value of land and coal interests, excluding the asset related to the Company's asset retirement obligations described below, was established at $3,504.7 million utilizing a discounted cash flow (DCF) model and the market approach. The market approach was used to provide a starting value of the coal mineral reserves without consideration for economic obsolescence. The DCF model was based on assumptions market participants would use in the pricing of these assets as well as projections of revenues and expenditures that would be incurred to mine or maintain these coal reserves through the life of mine. The basis of the DCF analysis was the Company's prepared projections which included a variety of estimates and assumptions, such as pricing and demand for coal. The Company's pricing was based on its view of the market taking into account third-party forward pricing curves adjusted for the quality of products sold by the Company. The fair value of land and coal interests also includes $281.2 million corresponding to the asset retirement obligation discussed in item (g) below.

The fair value of buildings and improvements and machinery and equipment were set at $466.1 million and $940.5 million, respectively, utilizing both market and cost approaches. The market approach was used to estimate the value of assets where detailed information for the asset was available and an active market was identified with a sufficient number of sales of comparable property that could be independently verified through reliable sources. The cost approach was utilized where there were limitations in the secondary equipment market to derive values from. The first step in the cost approach is the estimation of the cost required to replace the asset via construction or purchasing a new asset with similar utility adjusting for depreciation due to physical deterioration, functional obsolescence due to technology changes and economic obsolescence due to external factors such as regulatory changes. Useful lives were assigned to all assets based on remaining future economic benefit of each asset.

(d) Primarily to recognize fair value of $314.9 million inherent in certain U.S. coal supply agreements as a result of favorable differences between contract terms and estimated market terms for the same coal products, partially offset by a reduction in the fair value of certain equity method investments. The intangible asset related to coal supply agreements will be amortized on a per ton shipped basis through 2025.

(e) Represents $32.6 million to account for the short-term portion of the value of certain contract-based intangibles primarily consisting of unutilized capacity of certain port and rail take-or-pay contracts, partially offset by $15.7 million related to liabilities classified as held-for-sale at March 31, 2017 which were reclassified as held-for-use and considered in connection with the valuations described in (c) above, and various other fair value adjustments. The intangible liabilities related to port and rail take-or-pay contracts will be amortized ratably over the terms of each contact, which vary in duration through 2043.

(f) Represents the tax impact of fresh start reporting.

(g) Represents the fair value adjustment related to the Company's asset retirement obligations which was calculated using DCF models based on contemporary mine plans. The credit-adjusted, risk-free interest rates utilized to estimate the Company's asset retirement obligations were 9.36% for its U.S. reclamation obligations and 4.36% for its Australia reclamation obligations.

(h) Represents the remeasurement of liabilities associated with the Company's postretirement benefits obligations as of the Effective Date as the reorganization of the Company pursuant to the Plan represented a remeasurement event under ASC 715 "Compensation - Retirement Benefits." The relevant discount rate was adjusted to 4.10% from 4.15% used in the Company's remeasurement process for the year ended December 31, 2016.

(i) Represents $83.6 million to account for the long-term portion of the value of contract-based intangibles related to unutilized capacity of port and rail take-or-pay contracts as described in (e) above and $58.7 million to account for the fair value inherent in certain U.S. coal supply agreements as a result of unfavorable differences between contract terms and estimated market terms for the same coal products as described in (d) above, partially offset by a remeasurement reduction of $9.2 million of the Company's pension liabilities in accordance with ASC 715 as described in (h) above, as the relevant discount rate was adjusted to 4.10% from 4.15% used in the Company's remeasurement process for the year ended December 31, 2016, and certain other valuation adjustments.

(3) Acquisition of Shoal Creek Mine

On December 3, 2018, the Company completed the acquisition of the Shoal Creek metallurgical coal mine, preparation plant and supporting assets located in Alabama (Shoal Creek Mine) from Drummond Company, Inc. for a purchase price of $389.8 million after customary purchase price adjustments, which was funded with available cash on hand. The acquisition expanded the Company's seaborne metallurgical mining platform.

The acquisition excluded all liabilities other than reclamation and the Company is not responsible for other liabilities relating to the operation of the Shoal Creek Mine prior to the acquisition date, including employee benefit plans and post-employment benefits. In connection with completing the acquisition, a new collective bargaining agreement was reached with the union-represented workforce that eliminates participation in the multi-employer pension plan and replaces it with a 401(k) retirement plan.

The purchase accounting allocations were recorded in the accompanying consolidated financial statements as of, and for the period subsequent to the acquisition date. The following table summarizes the fair values of assets acquired and liabilities assumed that were recognized at the acquisition and control date as well as fair value adjustments made through December 31, 2019:

	Preliminary Allocations	Adjustments	Final Allocations
		(Dollars in millions)	
Inventories	$ 39.7	$ 0.2	$ 39.9
Property, plant, equipment and mine development	364.7	0.6	365.3
Current liabilities	(4.1)	—	(4.1)
Asset retirement obligations	(10.5)	(0.8)	(11.3)
Total purchase price	$ 389.8	$ —	$ 389.8

Determining the fair value of assets acquired and liabilities assumed required judgment and the utilization of independent valuation experts, and included the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items. Due to the unobservable inputs to the valuation, the fair value would be considered Level 3 in the fair value hierarchy.

The adjustments to the provisional fair values resulted from additional information obtained about facts in existence at the acquisition and control date and included rationalization adjustments in order to reconcile the aggregated fair value of the assets acquired to the amount of consideration transferred. Adjustments to provisional fair values were assumed to have been made as of the acquisition and control date. As a result, "Depreciation, depletion and amortization" would have been lower by $0.4 million, $0.5 million and $0.4 million for the fourth quarter of 2018, first quarter of 2019 and second quarter of 2019, respectively, than was previously reported. The accompanying consolidated statements of operations reflect these adjustments in the year ended December 31, 2019.

The Company has finalized the valuation of the net assets acquired and related purchase price allocation.

The results of Shoal Creek Mine for the year ended December 31, 2019 and the period December 4, 2018 through December 31, 2018 are included in the consolidated statements of operations and are reported in the Seaborne Metallurgical Mining segment. The Shoal Creek Mine contributed revenues of $12.8 million and less than $0.1 million of net income from December 4, 2018 through December 31, 2018. This excludes acquisition costs recorded during the year ended December 31, 2018 of $7.4 million, which primarily consisted of professional fees. These acquisition costs are recorded in the "Transaction costs related to business combinations and joint ventures" line item in the consolidated statements of operations.

As a result of Peabody's reorganization and change in reporting entity as described in Note 1. "Summary of Significant Accounting Policies," the following unaudited pro forma financial information presents the estimated combined results of operations of the Company and Shoal Creek Mine, on a pro forma basis, as though the operations of the Shoal Creek Mine had been combined with the Company's operations as of April 2, 2017. Pro forma information is not presented for the year ended December 31, 2019 because the operations of the Shoal Creek Mine are reflected in the Company's actual consolidated results for the entire year. The unaudited pro forma financial information does not necessarily reflect the results of operations that would have occurred had the operations of the Company and Shoal Creek Mine been combined during those periods or that may be attained in the future.

	Successor	
	Year Ended December 31, 2018	April 2 through December 31, 2017
	(Dollars in millions, except per share data)	
Revenues	$ 6,008.4	$ 4,506.2
Income from continuing operations, net of income taxes	826.6	783.3
Basic earnings per share from continuing operations	$ 5.84	$ 4.37
Diluted earnings per share from continuing operations	$ 5.75	$ 4.33

The pro forma income from continuing operations, net of income taxes includes adjustments to operating costs to reflect the additional expense for the estimated impact of the fair value adjustment for coal inventory, a reduction in postretirement benefit costs resulting from the new collective bargaining agreement described above, and the estimated impact on depreciation, depletion and amortization for the fair value adjustment for property, plant and equipment (including coal reserve assets). On a pro forma basis, the acquisition would have had no impact on taxable income due to the Company's federal net operating losses (NOLs), as further described in Note 12. "Income Taxes."

(4) Revenue Recognition

The Company accounts for revenue in accordance with ASC Topic 606, "Revenue from Contracts with Customers" (ASC 606), which the Company adopted on January 1, 2018, using the modified retrospective approach.

Disaggregation of Revenues

Revenue by product type and market is set forth in the following tables. With respect to its seaborne mining segments, the Company classifies as "Export" certain revenue from domestically-delivered coal under contracts in which the price is derived on a basis similar to export contracts.

	Successor						
	Year Ended December 31, 2019						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other [(1)]	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 147.9	$ —	$ 1,208.9	$ 669.2	$ 605.0	$ —	$ 2,631.0
Export	822.4	—	—	—	11.3	—	833.7
Total thermal	970.3	—	1,208.9	669.2	616.3	—	3,464.7
Metallurgical coal							
Export	—	1,030.0	—	—	—	—	1,030.0
Total metallurgical	—	1,030.0	—	—	—	—	1,030.0
Other	1.4	3.1	19.8	0.5	23.4	80.5	128.7
Revenues	$ 971.7	$ 1,033.1	$ 1,228.7	$ 669.7	$ 639.7	$ 80.5	$ 4,623.4

	Successor						
	Year Ended December 31, 2018						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 153.0	$ —	$ 1,424.8	$ 799.4	$ 543.1	$ —	$ 2,920.3
Export	945.0	—	—	1.3	22.1	—	968.4
Total thermal	1,098.0	—	1,424.8	800.7	565.2	—	3,888.7
Metallurgical coal							
Export	—	1,548.6	—	—	—	—	1,548.6
Total metallurgical	—	1,548.6	—	—	—	—	1,548.6
Other	1.2	4.4	—	0.3	26.8	111.8	144.5
Revenues	$ 1,099.2	$ 1,553.0	$ 1,424.8	$ 801.0	$ 592.0	$ 111.8	$ 5,581.8

	Successor						
	April 2 through December 31, 2017						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 87.9	$ —	$ 1,174.3	$ 586.7	$ 409.8	$ —	$ 2,258.7
Export	684.1	—	—	5.3	19.2	—	708.6
Total thermal	772.0	—	1,174.3	592.0	429.0	—	2,967.3
Metallurgical coal							
Export	—	1,221.0	—	—	—	—	1,221.0
Total metallurgical	—	1,221.0	—	—	—	—	1,221.0
Other	0.5	—	4.4	0.3	11.7	47.4	64.3
Revenues	$ 772.5	$ 1,221.0	$ 1,178.7	$ 592.3	$ 440.7	$ 47.4	$ 4,252.6

	Predecessor						
	January 1 through April 1, 2017						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
Thermal coal							
Domestic	$ 27.3	$ —	$ 394.3	$ 193.2	$ 133.5	$ —	$ 748.3
Export	197.2	—	—	—	—	—	197.2
Total thermal	224.5	—	394.3	193.2	133.5	—	945.5
Metallurgical coal							
Export	—	324.6	—	—	—	—	324.6
Total metallurgical	—	324.6	—	—	—	—	324.6
Other	0.3	4.3	—	—	16.2	35.3	56.1
Revenues	$ 224.8	$ 328.9	$ 394.3	$ 193.2	$ 149.7	$ 35.3	$ 1,326.2

Revenue by initial contract duration was as follows:

	Successor						
	Year Ended December 31, 2019						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
One year or longer	$ 589.2	$ 828.6	$ 1,087.6	$ 644.3	$ 609.9	$ —	$ 3,759.6
Less than one year	381.1	201.4	121.3	24.9	6.4	—	735.1
Other (2)	1.4	3.1	19.8	0.5	23.4	80.5	128.7
Revenues	$ 971.7	$ 1,033.1	$ 1,228.7	$ 669.7	$ 639.7	$ 80.5	$ 4,623.4

	Successor						
	Year Ended December 31, 2018						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
One year or longer	$ 799.5	$ 1,036.7	$ 1,283.9	$ 775.4	$ 531.8	$ —	$ 4,427.3
Less than one year	298.5	511.9	140.9	25.3	33.4	—	1,010.0
Other (2)	1.2	4.4	—	0.3	26.8	111.8	144.5
Revenues	$ 1,099.2	$ 1,553.0	$ 1,424.8	$ 801.0	$ 592.0	$ 111.8	$ 5,581.8

	Successor						
	April 2 through December 31, 2017						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
One year or longer	$ 503.0	$ 867.1	$ 1,023.1	$ 560.5	$ 404.6	$ —	$ 3,358.3
Less than one year	269.0	353.9	151.2	31.5	24.4	—	830.0
Other (2)	0.5	—	4.4	0.3	11.7	47.4	64.3
Revenues	$ 772.5	$ 1,221.0	$ 1,178.7	$ 592.3	$ 440.7	$ 47.4	$ 4,252.6

	Predecessor						
	January 1 through April 1, 2017						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other (1)	Consolidated
	(Dollars in millions)						
One year or longer	$ 134.1	$ 240.6	$ 357.7	$ 193.2	$ 129.3	$ —	$ 1,054.9
Less than one year	90.4	84.0	36.6	—	4.2	—	215.2
Other (2)	0.3	4.3	—	—	16.2	35.3	56.1
Revenues	$ 224.8	$ 328.9	$ 394.3	$ 193.2	$ 149.7	$ 35.3	$ 1,326.2

(1) Corporate and Other revenue includes gains and losses related to mark-to-market adjustments from economic hedge activities intended to hedge future coal sales. Refer to Note 9. “Derivatives and Fair Value Measurements” for additional information regarding the economic hedge activities.

(2) Other includes revenues from arrangements such as customer contract-related payments, royalties related to coal lease agreements, sales agency commissions, farm income and property and facility rentals, for which contract duration is not meaningful.

Committed Revenue from Contracts with Customers

The Company expects to recognize revenue subsequent to December 31, 2019 of approximately $4.7 billion related to contracts with customers in which volumes and prices per ton were fixed or reasonably estimable at December 31, 2019. Approximately 48% of such amount is expected to be recognized over the next twelve months and the remainder thereafter. Actual revenue related to such contracts may differ materially for various reasons, including price adjustment features for coal quality and cost escalations, volume optionality provisions and potential force majeure events. This estimate of future revenue does not include any revenue related to contracts with variable prices per ton that cannot be reasonably estimated, such as the majority of seaborne metallurgical and seaborne thermal coal contracts where pricing is negotiated or settled quarterly or annually.

Accounts Receivable

"Accounts receivable, net" at December 31, 2019 and 2018 consisted of the following:

	December 31,	
	2019	2018
	(Dollars in millions)	
Trade receivables, net	$ 283.1	$ 345.5
Miscellaneous receivables, net	46.4	104.9
Accounts receivable, net	$ 329.5	$ 450.4

Trade receivables, net presented above have been shown net of reserves of $0.1 million as of December 31, 2018. Trade receivables, net included no reserves as of December 31, 2019. Miscellaneous receivables, net presented above have been shown net of reserves of $4.3 million as of December 31, 2018. Miscellaneous receivables, net included no reserves as of December 31, 2019. Included in "Operating costs and expenses" in the consolidated statements of operations were credits of $4.4 million and $0.2 million for the years ended December 31, 2019 and 2018, respectively, and a charge of $4.3 million for the period ended April 2 through December 31, 2017. No charges for doubtful accounts were recognized during the period January 1 through April 1, 2017.

The Company also records long-term customer receivables related to the reimbursement of certain post-mining costs which are included within "Investments and other assets" in the accompanying consolidated balance sheets. The balance of such receivables was $11.1 million as of December 31, 2018. There were no such outstanding receivables as of December 31, 2019. Since the adoption of ASC 606, the Company records a portion of the consideration received as "Interest income" rather than "Revenues" in the accompanying consolidated statements of operations, due to the embedded financing element within the related contract. Interest income related to these arrangements amounted to $8.2 million and $8.4 million during the years ended December 31, 2019 and 2018, respectively.

(5) Asset Impairment

During the year ended December 31, 2019, the Company recognized impairment charges of $172.0 million related to its El Segundo/Lee Ranch Mine of the Western U.S. Mining segment and $20.0 million related to its Wildcat Hills Underground Mine of the Midwestern U.S. Mining segment based upon the expectation of reduced sales volumes and uncertainty over remaining economic mine lives. The related impairment charges were based upon the remaining probability-weighted discounted cash flows of those mines. The Company also recognized impairment charges of $69.2 million related to certain unallocated coal reserves in the Midwest and Colorado due to their low probability of development, and $9.0 million related to the fair value of an investment in equity securities during the year ended December 31, 2019. During the year ended December 31, 2018 and the period April 2 through December 31, 2017, the Company recognized no impairment charges. During the period January 1 through April 1, 2017, the Company recognized impairment charges of $30.5 million related to terminated coal lease contracts in the Midwest.

In addition to the impairment charges described above, the Company also recorded provisions related to its North Goonyella Mine during the year ended December 31, 2019, as further described at Note 22. "Other Events."

In connection with its impairment assessments, the Company identified long-lived assets included in its Midwestern U.S. Mining and Corporate and Other segments whose recoverability and carrying values were most sensitive to coal pricing, cost pressures and customer concentration risk at December 31, 2019. Such assets had an aggregate carrying value of $89.0 million as of December 31, 2019. The Company conducted a review of those assets for recoverability and determined that no further impairment charge was necessary as of that date.

(6) Discontinued Operations

Discontinued operations include certain former Seaborne Thermal Mining and Midwestern U.S. Mining segment assets that have ceased production and other previously divested legacy operations, including Patriot Coal Corporation and certain of its wholly-owned subsidiaries (Patriot).

Summarized Results of Discontinued Operations

Results from discontinued operations were as follows during the years ended December 31, 2019, 2018 and 2017:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Income (loss) from discontinued operations, net of income taxes	$ 3.2	$ 18.1	$ (19.8)	$ (16.2)

There were no significant revenues from discontinued operations during the years ended December 31, 2019, 2018 and 2017.

Liabilities of Discontinued Operations

Liabilities classified as discontinued operations included in the Company's consolidated balance sheets were as follows:

	December 31,	
	2019	2018
	(Dollars in millions)	
Liabilities:		
Accounts payable and accrued expenses	$ 58.8	$ 54.0
Other noncurrent liabilities	105.5	141.1
Total liabilities classified as discontinued operations	$ 164.3	$ 195.1

Patriot-Related Matters

A significant portion of the liabilities in the table above relate to Patriot. In 2012, Patriot filed voluntary petitions for relief under the Bankruptcy Code. In 2013, the Company entered into a definitive settlement agreement (2013 Agreement) with Patriot and the United Mine Workers of America (UMWA), on behalf of itself, its represented Patriot employees and its represented Patriot retirees, to resolve all then-disputed issues related to Patriot's bankruptcy. In May 2015, Patriot again filed voluntary petitions for relief under the Bankruptcy Code in the Eastern District of Virginia and subsequently initiated a process to sell some or all of its assets to qualified bidders. On October 9, 2015, Patriot's bankruptcy court entered an order confirming Patriot's plan of reorganization, which provided, among other things, for the sale of substantially all of Patriot's assets to two different buyers.

Black Lung Occupational Disease Liabilities. Patriot had federal and state black lung occupational disease liabilities related to workers employed in periods prior to Patriot's spin-off from the Company in 2007. Upon spin-off, Patriot indemnified the Company against any claim relating to these liabilities, which amounted to approximately $150 million at that time. The indemnification included any claim made by the U.S. Department of Labor (DOL) against the Company with respect to these obligations as a potentially liable operator under the Federal Coal Mine Health and Safety Act of 1969. The 2013 Agreement included Patriot's affirmance of indemnities provided in the spin-off agreements, including the indemnity relating to such black lung liabilities; however, Patriot rejected this indemnity in its May 2015 bankruptcy.

By statute, the Company had secondary liability for the black lung liabilities related to Patriot's workers employed by former subsidiaries of the Company. The Company's accounting for the black lung liabilities related to Patriot is based on an interpretation of applicable statutes. Management believes that inconsistencies exist among the applicable statutes, regulations promulgated under those statutes and the DOL's interpretative guidance. The Company has sought clarification from the DOL regarding these inconsistencies. The accounting for these liabilities could be reduced in the future. Whether the Company will ultimately be required to fund certain of those obligations in the future as a result of Patriot's May 2015 bankruptcy remains uncertain. The amount of the liability, which was determined on an actuarial basis based on the best information available to the Company was $85.7 million and $102.7 million at December 31, 2019 and 2018, respectively. In connection with the actuarial valuation, the Company recorded a mark-to-market adjustment of $18.3 million and $33.7 million to decrease the liability during the years ended December 31, 2019 and 2018, respectively and $7.9 million to increase the liability during the period April 2 through December 31, 2017. While the Company has recorded a liability, it intends to review each claim on a case-by-case basis and contest liability estimates as appropriate. The amount of the Company's recorded liability reflects only Patriot workers employed by former subsidiaries of the Company that are presently retired, disabled or otherwise not actively employed. The Company cannot reliably estimate the potential liabilities for Patriot's workers employed by former subsidiaries of the Company that are presently active in the workforce because of the potential for such workers to continue to work for another coal operator that is a going concern.

Combined Benefit Fund (Combined Fund). The Combined Fund was created by the Coal Act in 1992 as a multi-employer plan to provide health care benefits to a closed group of retirees who last worked prior to 1976, as well as orphaned beneficiaries of bankrupt companies who were receiving benefits as orphans prior to the passage of the Coal Act. No new retirees will be added to this group, which includes retirees formerly employed by certain Patriot subsidiaries and their predecessors. Former employers are required to contribute to the Combined Fund according to a formula.

Under the terms of the Patriot spin-off, Patriot was primarily liable to the Combined Fund for the approximately $40 million of its subsidiaries' obligations at that time. Once Patriot ceased meeting its obligations, the Company was held responsible for these costs and, as a result, recorded "Income (loss) from discontinued operations, net of income taxes" charges of $0.7 million, $0.7 million, $0.6 million and $0.2 million during the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively. The Company made payments into the fund of $1.9 million, $2.2 million, $1.7 million and $0.6 million during the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively, and estimates that the annual cash cost to fund these potential Combined Fund liabilities will range between $1 million and $2 million in the near-term, with those premiums expected to decline over time because the fund is closed to new participants. The liability related to the fund was $15.2 million and $16.4 million at December 31, 2019 and 2018, respectively.

UMWA 1974 Pension Plan (UMWA Plan) Litigation. On July 16, 2015, a lawsuit was filed by the UMWA Plan, the UMWA 1974 Pension Trust (Trust) and the Trustees of the UMWA Plan and Trust (Trustees) in the United States District Court for the District of Columbia, against the Company, Peabody Holding Company, LLC, a subsidiary of the Company, and Arch Coal, Inc. (Arch). The plaintiffs sought, pursuant to the Employee Retirement Income Security Act of 1974, as amended (ERISA) and the Multiemployer Pension Plan Amendments Act of 1980 (MPPAA), a declaratory judgment that the defendants were obligated to arbitrate any opposition to the Trustees' determination that the defendants had statutory withdrawal liability as a result of the 2015 Patriot bankruptcy. After a legal and arbitration process and with the approval of the Bankruptcy Court, on January 25, 2017, the UMWA Plan and the Company agreed to a settlement of the claim which entitled the UMWA Plan to $75 million to be paid by the Company in increments through 2021. The balance of the liability, on a discounted basis, was $26.0 million and $36.7 million at December 31, 2019 and 2018, respectively.

(7) Inventories

Inventories as of December 31, 2019 and December 31, 2018 consisted of the following:

	December 31, 2019	December 31, 2018
	(Dollars in millions)	
Materials and supplies	$ 116.3	$ 118.1
Raw coal	85.1	53.6
Saleable coal	130.1	108.5
Inventories	$ 331.5	$ 280.2

Materials and supplies inventories presented above have been shown net of reserves of $7.9 million and $0.2 million as of December 31, 2019 and 2018, respectively.

(8) Equity Method Investments

Equity Method Investments

The Company's equity method investments include its joint venture interest in Middlemount and certain other equity method investments.

The table below summarizes the book value of those investments and related financing receivables, which are reported in "Investments and other assets" in the consolidated balance sheets, and the related "Income from equity affiliates":

			Successor			Predecessor
	Book Value at		(Income) Loss from Equity Affiliates			
	December 31, 2019	December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)					
Equity method investment and financing receivables related to Middlemount	$ 56.3	$ 45.0	$ (9.0)	$ (69.3)	$ (48.6)	$ (17.4)
Other equity method investments	0.6	0.9	5.6	1.2	(0.4)	2.4
Total equity method investments and financing receivables related to Middlemount	$ 56.9	$ 45.9	$ (3.4)	$ (68.1)	$ (49.0)	$ (15.0)

As of December 31, 2019 and 2018, respectively, the financing receivables are accounted for as in-substance common stock due to the limited fair value attributed to Middlemount's equity.

The Company received cash payments from Middlemount of $14.7 million, $106.7 million, $48.1 million and $32.7 million during the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively.

One of the Company's Australian subsidiaries and the other shareholder of Middlemount are parties to an agreement, as amended from time to time, to provide a revolving loan (Revolving Loans) to Middlemount. The Company's participation in the Revolving Loans will not, at any time, exceed its 50% equity interest of the revolving loan limit, which was $50 million Australian dollars and fully drawn upon by Middlemount at December 31, 2019. Subsequent to December 31, 2019, the parties amended the agreement to temporarily increase the revolving loan limit to $70 million Australian dollars through August 2020, at which time the revolving loan limit will revert to $50 million Australian dollars.

The Revolving Loans bear interest at 15% per annum and expire on December 31, 2020. The carrying value of the Revolving Loans due to the Company's Australian subsidiary was $17.1 million and zero as of December 31, 2019 and 2018, respectively.

During the year ended December 31, 2018 the Company determined that a valuation allowance on Middlemount's net deferred tax position was no longer necessary based on recent cumulative earnings and expectation of future earnings. The determination resulted in approximately $9 million of income which was more than offset by a tax reserve of approximately $17 million due to an uncertain tax position relating to an ongoing income tax audit of Middlemount. During the year ended December 31, 2019, Middlemount received notification that the Australian Taxation Office would no longer pursue its position, and the related tax reserve was released.

During the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017, and the period January 1 through April 1, 2017, respectively, Middlemount generated revenues of approximately $160 million, $271 million, $193 million and $60 million (on a 50% basis).

Middlemount had current assets, noncurrent assets, current liabilities and noncurrent liabilities of $30.8 million, $209.7 million, $225.8 million and $40.1 million, respectively, as of December 31, 2019 and $33.6 million, $181.8 million, $187.9 million and $35.8 million, respectively, as of December 31, 2018 (on a 50% basis).

(9) Derivatives and Fair Value Measurements

Derivatives

Corporate Risk Management Activities

From time to time, the Company may utilize various types of derivative instruments to manage its exposure to risks in the normal course of business, including (1) foreign currency exchange rate risk and the variability of cash flows associated with forecasted Australian dollar expenditures made in its Australian mining platform, (2) price risk of fluctuating coal prices related to forecasted sales or purchases of coal, or changes in the fair value of a fixed price physical sales contract, (3) price risk and the variability of cash flows related to forecasted diesel fuel purchased for use in its operations, and (4) interest rate risk on long-term debt. These risk management activities are actively monitored for compliance with the Company's risk management policies.

As of December 31, 2019, the Company had currency options outstanding with an aggregate notional amount of $925.0 million Australian dollars to hedge currency risk associated with anticipated Australian dollar expenditures over the first nine months of 2020. The instruments are quarterly average rate options which entitle the Company to receive payment on the notional amount should the quarterly average Australian dollar-to-U.S. dollar exchange rate exceed amounts ranging from $0.73 to $0.75 over the first nine months of 2020.

As of December 31, 2019, the Company held coal-related financial contracts related to a portion of its forecasted sales for an aggregate notional volume of 2.0 million tonnes. Such financial contracts include futures, forwards and options. Of the aggregate notional volume, 1.7 million tonnes will settle in 2020 and the remainder will settle in 2021.

The Company had no diesel fuel or interest rate derivatives in place as of December 31, 2019.

Coal Trading Activities

On a limited basis, the Company engages in the direct and brokered trading of coal and freight-related contracts (coal trading). Except those contracts for which the Company has elected to apply a normal purchases and normal sales exception, all derivative coal trading contracts are accounted for at fair value. Coal brokering is conducted both as principal and agent in support of various coal production-related activities that may involve coal produced from the Company's mines, coal sourcing arrangements with third-party mining companies or offtake agreements with other coal producers. The Company also provides transportation-related services, which involve 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 the Company's coal trading strategy. Revenues from such transactions include realized and unrealized gains and losses on derivative instruments, including those that arise from coal deliveries related to contracts accounted for on an accrual basis under the normal purchases and normal sales exception.

Offsetting and Balance Sheet Presentation

The Company has master netting agreements with certain of its counterparties which allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. Such netting arrangements reduce the Company's credit exposure related to these counterparties. For classification purposes, the Company records the net fair value of all the positions with a given counterparty as a net asset or liability in the consolidated balance sheets.

The Company's coal trading assets and liabilities include financial instruments cleared through various exchanges, which involve the daily net settlement of open positions. The Company must post cash collateral in the form of initial margin, in addition to variation margin, on exchange-cleared positions that are in a net liability position and receives variation margin when in a net asset position. The Company also transacts in coal trading financial swaps and options through over-the-counter (OTC) markets with financial institutions and other non-financial trading entities under International Swaps and Derivatives Association (ISDA) Master Agreements, which contain symmetrical default provisions. Certain of the Company's coal trading agreements with OTC counterparties also contain credit support provisions that may periodically require the Company to post, or entitle the Company to receive, variation margin. Physical coal and freight-related purchase and sale contracts included in the Company's coal trading assets and liabilities are executed pursuant to master purchase and sale agreements that also contain symmetrical default provisions and allow for the netting and setoff of receivables and payables that arise during the same time period. The Company offsets its coal trading asset and liability derivative positions, and variation margin related to those positions, on a counterparty-by-counterparty basis in the consolidated balance sheets.

The fair value of derivatives reflected in the accompanying consolidated balance sheets are set forth in the table below.

	December 31, 2019		December 31, 2018	
	Asset Derivative	Liability Derivative	Asset Derivative	Liability Derivative
	(Dollars in millions)			
Foreign currency option contracts	$ 1.1	$ —	$ 1.2	$ —
Coal contracts related to forecasted sales	20.1	(0.1)	6.6	(23.1)
Coal trading contracts	81.1	(74.2)	59.7	(64.4)
Total derivatives	102.3	(74.3)	67.5	(87.5)
Effect of counterparty netting	(74.3)	74.3	(64.5)	64.5
Variation margin (held) posted	(22.1)	—	—	21.8
Net derivatives and margin as classified in the balance sheets	$ 5.9	$ —	$ 3.0	$ (1.2)

The net amount of asset derivatives, net of margin, are included in "Other current assets" and the net amount of liability derivatives, net of margin, are included in "Accounts payable and accrued expenses" in the accompanying consolidated balance sheets.

Effects of Derivatives on Measures of Financial Performance

Currently, the Company does not seek cash flow hedge accounting treatment for its currency- or coal-related derivative financial instruments and thus changes in fair value are reflected in current earnings.

Prior to the Bankruptcy Petitions, as of December 31, 2015, the Company concluded that as a result of deterioration in its credit profile, it could no longer consider its then existing cash flow hedging relationships to be "highly effective" at offsetting the changes in the anticipated exposure of hedged items. Therefore, the Company discontinued the application of cash flow hedge accounting subsequent to December 31, 2015 and changes in the fair value of derivative instruments have been reflected in current earnings after that date. Previous fair value adjustments recorded in "Accumulated other comprehensive income" were frozen until the underlying transactions impacted the Company's earnings.

The tables below show the amounts of pre-tax gains and losses related to the Company's derivatives.

	Successor		
	Year Ended December 31, 2019		
Financial Instrument	Total (loss) gain recognized in income	(Loss) gain realized in income on derivatives	Unrealized gain recognized in income on derivatives
	(Dollars in millions)		
Foreign currency option contracts	$ (3.7)	$ (4.9)	$ 1.2
Coal contracts related to forecasted sales	67.6	25.4	42.2
Coal trading contracts	(0.3)	(8.7)	8.4
Total	$ 63.6	$ 11.8	$ 51.8

	Successor		
	Year Ended December 31, 2018		
Financial Instrument	Total (loss) gain recognized in income	(Loss) gain realized in income on derivatives	Unrealized (loss) gain recognized in income on derivatives
	(Dollars in millions)		
Foreign currency option contracts	$ (9.1)	$ (8.4)	$ (0.7)
Coal contracts related to forecasted sales	115.7	97.4	18.3
Coal trading contracts	(2.9)	(5.3)	2.4
Total	$ 103.7	$ 83.7	$ 20.0

	Successor		
	April 2 through December 31, 2017		
Financial Instrument	Total gain (loss) recognized in income	Gain (loss) realized in income on derivatives	Unrealized (loss) gain recognized in income on derivatives
	(Dollars in millions)		
Foreign currency option contracts	$ 1.8	$ 3.3	$ (1.5)
Coal contracts related to forecasted sales	12.1	35.1	(23.0)
Coal trading contracts	(1.6)	(8.3)	6.7
Total	$ 12.3	$ 30.1	$ (17.8)

	Predecessor			
	January 1 through April 1, 2017			
Financial Instrument	Total (loss) gain recognized in income	Gain (loss) realized in income on derivatives	Unrealized gain recognized in income on derivatives	Loss reclassified from other comprehensive loss into income
	(Dollars in millions)			
Commodity swap contracts	$ (11.0)	$ —	$ —	$ (11.0)
Foreign currency forward contracts	(16.6)	—	—	(16.6)
Financial coal contracts - Company production	29.2	12.7	16.5	—
Coal trading contracts	2.2	(11.3)	13.5	—
Total	$ 3.8	$ 1.4	$ 30.0	$ (27.6)

During the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, gains and losses on foreign currency option contracts and commodity swap contracts were included in "Operating costs and expenses," and gains and losses on coal contracts related to forecasted sales and those related to coal trading contracts were included in "Revenues" in the accompanying consolidated statements of operations.

The Company classifies the cash effects of its derivatives within the “Cash Flows From Operating Activities” section of the consolidated statements of cash flows.

Fair Value Measurements

The Company uses a three-level fair value hierarchy that categorizes assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. These levels include: Level 1 - inputs are quoted prices in active markets for the identical assets or liabilities; Level 2 - inputs are other than quoted prices included in Level 1 that are directly or indirectly observable through market-corroborated inputs; and Level 3 - inputs are unobservable, or observable but cannot be market-corroborated, requiring the Company to make assumptions about pricing by market participants.

The following tables set forth the hierarchy of the Company’s net financial asset (liability) positions for which fair value is measured on a recurring basis:

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Foreign currency option contracts	$ —	$ 1.1	$ —	$ 1.1
Coal contracts related to forecasted sales	—	21.2	—	21.2
Coal trading contracts	—	(16.4)	—	(16.4)
Equity securities	—	—	4.0	4.0
Total net financial assets	$ —	$ 5.9	$ 4.0	$ 9.9

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Foreign currency option contracts	$ —	$ 1.2	$ —	$ 1.2
Coal contracts related to forecasted sales	—	(21.2)	—	(21.2)
Coal trading contracts	—	21.8	—	21.8
Equity securities	—	—	10.0	10.0
Total net financial assets	$ —	$ 1.8	$ 10.0	$ 11.8

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including interest rate yield curves, exchange indices, broker/dealer quotes, published indices, issuer spreads, benchmark securities and other market quotes. In the case of certain debt securities, fair value is provided by a third-party pricing service. Below is a summary of the Company’s valuation techniques for Level 1 and 2 financial assets and liabilities:

- Foreign currency option contracts: valued utilizing inputs obtained in quoted public markets (Level 2) except when credit and non-performance risk is considered to be a significant input, then the Company classifies such contracts as Level 3.
- Coal contracts related to forecasted sales and coal trading contracts: generally valued based on unadjusted quoted prices in active markets (Level 1) or a valuation that is corroborated by the use of market-based pricing (Level 2) except when credit and non-performance risk is considered to be a significant input (greater than 10% of fair value), then the Company classifies as Level 3.
- Investments in equity securities are based on observed prices in an inactive market (Level 3).

Other Financial Instruments. The following methods and assumptions were used by the Company in estimating fair values for other financial instruments as of December 31, 2019 and 2018:

- Cash and cash equivalents, restricted cash, accounts receivable, including those within the Company’s accounts receivable securitization program, notes receivable and accounts payable have carrying values which approximate fair value due to the short maturity or the liquid nature of these instruments.
- Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available (Level 2), and otherwise on estimated borrowing rates to discount the cash flows to their present value (Level 3).

Market risk associated with the Company's fixed- and variable-rate long-term debt relates to the potential reduction in the fair value and negative impact to future earnings, respectively, from an increase in interest rates. The fair value of debt, shown below, is principally based on reported market values, recently completed market transactions and estimates based on interest rates, maturities, credit risk and underlying collateral.

	December 31,	
	2019	2018
	(Dollars in millions)	
Total debt at par value	$ 1,367.2	$ 1,437.0
Less: Unamortized debt issuance costs and original issue discount	(56.4)	(70.0)
Net carrying amount	$ 1,310.8	$ 1,367.0
Estimated fair value	$ 1,271.1	$ 1,366.2

The Company's risk management function, which is independent of the Company's coal trading function, is responsible for valuation policies and procedures, with oversight from executive management. Generally, the Company's Level 3 instruments or contracts are valued using bid/ask price quotations and other market assessments obtained from multiple, independent third-party brokers or other transactional data incorporated into internally-generated discounted cash flow models. Decreases in the number of third-party brokers or market liquidity could erode the quality of market information and therefore the valuation of the Company's market positions. The Company's valuation techniques include basis adjustments to the foregoing price inputs for quality, such as sulfur and ash content, location differentials, expressed as port and freight costs, and credit risk. The Company's risk management function independently validates the Company's valuation inputs, including unobservable inputs, with third-party information and settlement prices from other sources where available. A daily process is performed to analyze market price changes and changes to the portfolio. Further periodic validation occurs at the time contracts are settled with the counterparty. These valuation techniques have been consistently applied in all periods presented, and the Company believes it has obtained the most accurate information available for the types of derivative contracts held.

Significant increases or decreases in the inputs in isolation could result in a significantly higher or lower fair value measurement. The unobservable inputs do not have a direct interrelationship; therefore, a change in one unobservable input would not necessarily correspond with a change in another unobservable input.

The following table summarizes the changes in the Company's recurring Level 3 net financial assets (liabilities):

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Beginning of period	$ 10.0	$ —	$ (0.7)	$ (1.1)
Transfers into Level 3	—	—	—	—
Transfers out of Level 3	—	—	0.7	0.2
Total (losses) gains realized/unrealized:				
Included in earnings	(9.0)	(1.7)	—	0.2
Purchases	3.0	10.0	—	—
Sales	—	—	—	—
Settlements	—	1.7	—	—
End of period	$ 4.0	$ 10.0	$ —	$ (0.7)

The Company had no transfers between Levels 1 and 2 during any of the periods presented in the table above. Transfers of liabilities into/out of Level 3 from/to Level 2 during the periods presented were due to the relative value of unobservable inputs to the total fair value measurement of certain derivative contracts falling below, or in the case of transfers in, rising above, the 10% threshold. The Company's policy is to value all transfers between levels using the beginning of period valuation.

The following table summarizes the changes in net unrealized gains relating to Level 3 net financial liabilities held both as of the beginning and the end of the period:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Changes in unrealized gains (1)	$ —	$ —	$ —	$ 0.3

(1) Within the consolidated statements of operations and consolidated statements of comprehensive income for the periods presented, unrealized gains from Level 3 items are combined with unrealized gains and losses on positions classified in Level 1 or 2, as well as other positions that have been realized during the applicable periods.

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

As of December 31, 2019, 91% of the Company's credit exposure related to coal trading activities was with investment grade counterparties and 9% was with counterparties that are not rated.

Performance Assurances and Collateral

The Company is required by the exchanges upon which it transacts to post certain additional collateral, known as initial margin, which represents an estimate of potential future adverse price movements across the Company's portfolio under normal market conditions. The Company posted initial margin of $7.9 million and $16.7 million as of December 31, 2019 and 2018, respectively, which is reflected in "Other current assets" in the consolidated balance sheets. As of December 31, 2019 and 2018, respectively, the Company had posted $1.3 million and $2.2 million in excess of margin requirements.

The Company is required to post variation margin on positions that are in a net liability position and is entitled to receive and hold variation margin on positions that are in a net asset position with an exchange and certain of its OTC derivative contract counterparties. As of December 31, 2019, the Company was in receipt of $22.1 million in variation margin, while it had posted $21.8 million of net variation margin at December 31, 2018.

Certain of the Company's derivative trading instruments require the parties to provide additional performance assurances whenever a material adverse event jeopardizes one party's ability to perform under the instrument. If the Company was to sustain a material adverse event (using commercially reasonable standards), its counterparties could request collateralization on derivative trading instruments in which the Company holds a net liability position. Based on the aggregate fair values of such net liability positions at December 31, 2019 and 2018, the Company would have been required to post additional collateral of approximately $0.0 million and $1.3 million, respectively. As of December 31, 2019 and 2018, the Company was not required to post collateral to counterparties for such positions.

(10) Intangible Contract Assets and Liabilities

The Company has recorded intangible assets and liabilities to reflect the fair value of certain U.S. coal supply agreements as a result of differences between contract terms and estimated market terms for the same coal products, and also recorded intangible liabilities related to unutilized capacity under its port and rail take-or-pay contracts. The balances, net of accumulated amortization, and respective balance sheet classifications at December 31, 2019 and 2018, are set forth in the following tables:

	December 31, 2019		
	Assets	Liabilities	Net Total
	(Dollars in millions)		
Coal supply agreements	$ 20.7	$ (21.4)	$ (0.7)
Take-or-pay contracts	—	(40.0)	(40.0)
Total	$ 20.7	$ (61.4)	$ (40.7)
Balance sheet classification:			
Investments and other assets	$ 20.7	$ —	$ 20.7
Accounts payable and accrued expenses	—	(8.4)	(8.4)
Other noncurrent liabilities	—	(53.0)	(53.0)
Total	$ 20.7	$ (61.4)	$ (40.7)

	December 31, 2018		
	Assets	Liabilities	Net Total
	(Dollars in millions)		
Coal supply agreements	$ 70.9	$ (32.9)	$ 38.0
Take-or-pay contracts	—	(57.1)	(57.1)
Total	$ 70.9	$ (90.0)	$ (19.1)
Balance sheet classification:			
Investments and other assets	$ 70.9	$ —	$ 70.9
Accounts payable and accrued expenses	—	(20.3)	(20.3)
Other noncurrent liabilities	—	(69.7)	(69.7)
Total	$ 70.9	$ (90.0)	$ (19.1)

Amortization of the intangible assets and liabilities related to coal supply agreements occurs ratably based upon coal volumes shipped per contract and is recorded as a component of “Depreciation, depletion and amortization” in the accompanying consolidated statements of operations. Such amortization amounted to $23.2 million, $93.0 million and $121.3 million during the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017 respectively. During the year ended December 31, 2019, the Company also charged to expense intangible assets of $15.5 million related to a coal supply agreement deemed to have been impaired, as further described in Note 5. “Asset Impairment.” The Company anticipates net amortization of sales contracts, based upon expected shipments, to be an expense of approximately $7 million and $1 million for the years 2020 and 2021, respectively, and credits of $2 million per year for the years 2022 through 2024, and $3 million in total thereafter.

Future unutilized capacity and the amortization periods related to the take-or-pay contract intangible liabilities are based upon estimates of forecasted usage. Such amortization, which is classified as a reduction to “Operating costs and expenses” in the accompanying consolidated statements of operations, amounted to $16.6 million, $26.6 million and $22.5 million during the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017 respectively. The Company anticipates net amortization of take-or-pay contract intangible liabilities for the years 2020 through 2024 to be approximately $8 million, $4 million, $3 million, $3 million and $3 million, respectively, and $19 million in total thereafter.

(11) Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development, net, as of December 31, 2019 and December 31, 2018 consisted of the following:

	December 31, 2019	December 31, 2018
	(Dollars in millions)	
Land and coal interests	$ 4,022.4	$ 4,148.8
Buildings and improvements	547.9	559.3
Machinery and equipment	1,518.6	1,456.3
Less: Accumulated depreciation, depletion and amortization	(1,409.8)	(957.4)
Property, plant, equipment and mine development, net	$ 4,679.1	$ 5,207.0

Land and coal interests included coal reserves with a net book value of $2.8 billion as of December 31, 2019 and $3.0 billion as of December 31, 2018. Such coal reserves were comprised of mineral rights for leased coal interests and advance royalties that had a net book value of $2.0 billion and $2.1 billion as of December 31, 2019 and 2018, respectively, and coal reserves held by fee ownership of $0.8 billion and $0.9 billion at December 31, 2019 and 2018, respectively. The amount of coal reserves not subject to current depletion at properties where the Company was not currently engaged in mining operations or leasing to third parties was $0.1 billion and $0.2 billion as of December 31, 2019 and 2018, respectively.

Land and coal interests also include acquired interests in mineral rights at certain Australian exploration properties that had a net book value of $0.1 billion as of December 31, 2019 and 2018.

(12) Income Taxes

(Loss) income from continuing operations before income taxes for the periods presented below consisted of the following:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
U.S.	$ (374.2)	$ (43.4)	$ 10.4	$ 2,408.7
Non-U.S.	231.9	707.5	541.7	(2,868.0)
Total	$ (142.3)	$ 664.1	$ 552.1	$ (459.3)

Total income tax provision (benefit) for the periods presented below consisted of the following:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Current:				
U.S. federal	$ (21.5)	$ (46.8)	$ (101.4)	$ (3.1)
Non-U.S.	28.4	29.8	40.4	8.3
State	(0.3)	(0.1)	(0.4)	(6.7)
Total current	6.6	(17.1)	(61.4)	(1.5)
Deferred:				
U.S. federal	20.3	30.4	(85.1)	(101.0)
Non-U.S.	19.3	5.7	(14.5)	(160.4)
State	(0.2)	(0.6)	—	(0.9)
Total deferred	39.4	35.5	(99.6)	(262.3)
Total income tax provision (benefit)	$ 46.0	$ 18.4	$ (161.0)	$ (263.8)

The following is a reconciliation of the expected statutory federal income tax (benefit) expense to the Company's income tax provision (benefit) for the periods presented below:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Expected income tax (benefit) expense at U.S. federal statutory rate	$ (29.9)	$ 139.5	$ 193.2	$ (160.8)
Changes in valuation allowance, income tax	(32.0)	(284.6)	(744.9)	(777.2)
Remeasurement due to the Tax Cuts and Jobs Act	—	9.5	473.5	—
Reorganization costs	—	—	—	2,130.0
Bad debt deduction	—	—	—	(1,639.6)
Changes in tax reserves	3.0	2.1	7.2	(9.2)
Excess depletion	(19.3)	(28.5)	(40.4)	(11.2)
Foreign earnings repatriation	76.1	—	—	—
Foreign earnings provision differential	45.6	97.1	(26.3)	158.2
Global intangible low-taxed income	6.1	68.2	—	—
Remeasurement of foreign income tax accounts	(0.1)	(0.2)	(0.3)	9.4
State income taxes, net of federal tax benefit	(13.2)	3.2	(3.1)	40.6
Other, net	9.7	12.1	(19.9)	(4.0)
Total income tax provision (benefit)	$ 46.0	$ 18.4	$ (161.0)	$ (263.8)

Certain reconciliation items included in the above table exclude the remeasurement of foreign income tax accounts as these foreign currency effects are separately presented.

The Plan provided that the Company's pre-petition equity and certain obligations were canceled and extinguished and a significant portion of its long-term debt was discharged in exchange for new Common Stock and other consideration. The Company excluded cancellation of debt income (CODI) with respect to the Plan from its taxable income in accordance with U.S. Internal Revenue Code (IRC) Section 108 and reduced certain income tax attributes by the amount of such CODI.

On December 22, 2017, the Tax Cuts and Jobs Act (the Act) was signed into law making significant changes to the IRC. Key provisions of the Act that impacted the Company include: (i) repeal of the corporate alternative minimum tax (AMT) system, (ii) reduction of the U.S. federal corporate tax rate from 35% to 21% and (iii) the new global intangible low-taxed income (GILTI). Due to the repeal of the corporate AMT system, the Company's existing AMT credits as of December 31, 2017 are anticipated to be refunded through the 2021 federal tax return. During 2019, the Company received a refund of $45.7 million and is expecting an additional refund of $23.4 million in 2020. Deferred tax assets and liabilities attributable to the U.S. were remeasured from 35% to the reduced tax rate of 21%. The Company recorded a provision of $473.5 million and an offsetting valuation allowance adjustment for the remeasurement for the period April 2 through December 31, 2017. The Company recorded an additional provision of $9.5 million during the year ended December 31, 2018 upon completion of the filing of both U.S. and foreign tax returns for the 2017 tax year and an offsetting valuation allowance. The Company elected to recognize the tax on GILTI as a period expense in the period the tax is incurred and recorded a provision of $6.1 million and $68.2 million for the years ended December 31, 2019 and 2018, which was fully offset by the release of valuation allowance associated with the NOLs that absorbed the GILTI inclusion.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities as of December 31, 2019 and 2018 consisted of the following:

	December 31,	
	2019	2018
	(Dollars in millions)	
Deferred tax assets:		
Tax loss carryforwards and credits	$ 1,530.9	$ 1,729.3
Property, plant, equipment and mine development, principally due to differences in depreciation, depletion and asset impairments	276.6	304.5
Accrued postretirement benefit obligations	142.6	139.5
Asset retirement obligations	86.6	47.2
Employee benefits	25.3	24.8
Take or pay obligations	12.0	17.1
Investments and other assets	89.0	82.7
Workers' compensation obligations	7.6	6.2
Operating lease right-of-use assets	20.8	—
Other	16.7	38.2
Total gross deferred tax assets	2,208.1	2,389.5
Valuation allowance, income tax	(2,068.4)	(2,094.3)
Total deferred tax assets	139.7	295.2
Deferred tax liabilities:		
Property, plant, equipment and mine development, principally due to differences in depreciation, depletion and asset impairments	100.9	203.4
Operating lease liabilities	20.8	—
Coal supply agreements	3.1	9.3
Investments and other assets	15.4	43.7
Total deferred tax liabilities	140.2	256.4
Net deferred tax (liability) asset	$ (0.5)	$ 38.8
Deferred taxes are classified as follows:		
Noncurrent deferred income tax asset	$ 28.3	$ 48.5
Noncurrent deferred income tax liability	(28.8)	(9.7)
Net deferred tax (liability) asset	$ (0.5)	$ 38.8

As of December 31, 2019, the Company had gross Australia NOLs of $3.2 billion in Australian dollars and gross U.S. federal NOLs of $2.5 billion. The Company's tax loss carryforwards and credits of $1.5 billion as of December 31, 2019 were comprised primarily of net Australia NOLs and capital tax loss carryforwards of $766.4 million, net federal NOLs of $530.6 million, state NOLs of $81.5 million, AMT credits of $23.4 million, tax general business credits (GBCs) of $112.6 million and other foreign NOLs of $14.5 million. The AMT credits will be fully refunded by 2022. The foreign tax loss carryforwards have no expiration date. The federal NOLs begin to expire in 2036. The state NOLs begin to expire in 2023, and the GBCs begin to expire in 2027.

In assessing the near-term use of NOLs and tax credits and corresponding valuation allowance adjustments, the Company evaluated the expected level of future taxable income, available tax planning strategies, reversals of existing taxable temporary differences and taxable income in carryback years. For the year ended December 31, 2019, the Company continued to record valuation allowances of $2.1 billion against net deferred tax asset positions, comprised primarily of $0.9 billion in the U.S. and $1.2 billion in Australia. Recognition of those valuation allowances was 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 income"), which limited the Company's ability to look to future taxable income in assessing the realizability of the related assets.

Unrecognized Tax Benefits

Net unrecognized tax benefits (excluding interest and penalties) were recorded as follows in the consolidated balance sheets as of December 31, 2019 and 2018:

	December 31, 2019	December 31, 2018
	(Dollars in millions)	
Deferred income taxes	$ 15.5	$ 13.0
Other noncurrent liabilities	1.0	1.0
Net unrecognized tax benefits	$ 16.5	$ 14.0
Gross unrecognized tax benefits	$ 16.5	$ 14.0

The amount of the Company's gross unrecognized tax benefits increased by $2.5 million since December 31, 2018 due to adjustments to existing positions and additions for current positions. The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate was $16.5 million and $14.0 million at December 31, 2019 and 2018, respectively. A reconciliation of the beginning and ending amount of gross unrecognized tax benefits for the periods presented below is as follows:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Balance at beginning of period	$ 14.0	$ 12.7	$ 12.5	$ 20.1
Additions for current year tax positions	2.2	1.8	0.8	—
Additions (reductions) for prior year tax positions	0.3	—	(0.5)	(7.6)
Reductions for settlements with tax authorities	—	(0.5)	(0.1)	—
Balance at end of period	$ 16.5	$ 14.0	$ 12.7	$ 12.5

The Company recognizes interest and penalties related to unrecognized tax benefits in its income tax provision. The Company recorded $0.4 million, $0.4 million and $4.8 million of gross interest and penalties for the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017, respectively, and reversed gross interest and penalties of $2.1 million for the period January 1 through April 1, 2017. The Company had $5.8 million and $5.4 million of accrued gross interest and penalties related to unrecognized tax benefits at December 31, 2019 and 2018, respectively.

The Company expects a decrease of $5.3 million in its net unrecognized tax benefits during the next twelve months.

Tax Returns Subject to Examination

The Company's federal income tax returns for the 2016 through 2018 tax years are subject to potential examinations by the Internal Revenue Service. The Company's state income tax returns for the tax years 2000 and thereafter remain potentially subject to examination by various state taxing authorities due to NOL carryforwards. Australian income tax returns for tax years 2013 through 2018 continue to be subject to potential examinations by the Australian Taxation Office.

Foreign Earnings

As of December 31, 2019, the Company has a consolidated earnings deficit outside the U.S. but with some immaterial unremitted earnings in certain jurisdictions. The Company continues to be permanently reinvested with respect to its historical earnings. However, when appropriate, the Company has the ability to access foreign cash without incurring residual cash taxes due to the existence of NOLs.

Tax Payments and Refunds

The following table summarizes the Company's income tax (refunds) payments, net for the periods presented below:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
U.S. — federal	$ (45.7)	$ (103.1)	$ (11.2)	$ —
U.S. — state and local	0.3	(1.6)	—	—
Non-U.S.	36.3	40.7	10.4	5.5
Total income tax (refunds) payments, net	$ (9.1)	$ (64.0)	$ (0.8)	$ 5.5

(13) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31,	
	2019	2018
	(Dollars in millions)	
Trade accounts payable	$ 254.8	$ 281.7
Accrued payroll and related benefits	186.2	209.3
Other accrued expenses	118.5	184.9
Accrued taxes other than income	99.0	111.4
Asset retirement obligations	98.2	63.8
Accrued royalties	61.7	52.7
Liabilities associated with discontinued operations	58.8	54.0
Operating lease liabilities	29.6	—
Accrued health care insurance	15.8	10.0
Accrued interest	15.0	15.7
Workers' compensation obligations	8.4	7.0
Intangible take-or-pay contracts	8.4	20.3
Income taxes payable	2.6	10.0
Liabilities from coal trading activities	—	1.2
Accounts payable and accrued expenses	$ 957.0	$ 1,022.0

(14) Long-term Debt

In accordance with the Plan, the Company was recapitalized with new debt and equity instruments, including the 6.000% Senior Secured Notes due March 2022, the 6.375% Senior Secured Notes due March 2025 and the Senior Secured Term Loan due 2025 in the table below. The Company's total indebtedness as of December 31, 2019 and December 31, 2018 consisted of the following:

	December 31,	
	2019	2018
	(Dollars in millions)	
6.000% Senior Secured Notes due March 2022	$ 459.0	$ 500.0
6.375% Senior Secured Notes due March 2025	500.0	500.0
Senior Secured Term Loan due 2025, net of original issue discount	392.1	395.9
Finance lease obligations	15.2	40.0
Less: Debt issuance costs	(55.5)	(68.9)
	1,310.8	1,367.0
Less: Current portion of long-term debt	18.3	36.5
Long-term debt	$ 1,292.5	$ 1,330.5

In connection with the Chapter 11 Cases, the Company was required to pay adequate protection payments of $29.8 million to certain first lien creditors of the Predecessor company during the period January 1 through April 1, 2017. The adequate protection payments were recorded as "Interest expense" in the consolidated statements of operations and ceased upon the Effective Date. The Company did not record interest expense subsequent to the filing of the Bankruptcy Petitions for the majority of non-first lien Predecessor indebtedness, which was automatically stayed in accordance with Section 502(b)(2) of the Bankruptcy Code. The amount of contractual interest stayed was $92.9 million for the period January 1, 2017 through the Effective Date.

6.000% and 6.375% Senior Secured Notes

On February 15, 2017, one of PEC's subsidiaries entered into an indenture (the Indenture) with Wilmington Trust, National Association, as trustee, relating to its issuance of $500.0 million aggregate principal amount of 6.000% senior secured notes due 2022 (the 2022 Notes) and $500.0 million aggregate principal amount of 6.375% senior secured notes due 2025 (the 2025 Notes and, together with the 2022 Notes, the Senior Notes). The Senior Notes were sold on February 15, 2017 in a private transaction exempt from the registration requirements of the Securities Act of 1933.

The Senior Notes were issued at par value. The Company paid aggregate debt issuance costs of $49.5 million related to the offering, which will be amortized over the respective terms of the Senior Notes. Interest payments on the Senior Notes are scheduled to occur each year on March 31st and September 30th until maturity. During the years ended December 31, 2019 and 2018, the Company recorded interest expense of $72.0 million and $71.9 million, respectively, related to the Senior Notes.

The Company may redeem the 2022 Notes beginning March 31, 2019, in whole or in part, at 103.0% of par, beginning March 31, 2020 at 101.5% of par and beginning March 31, 2021 and thereafter at par. The 2025 Notes may be redeemed, in whole or in part, beginning March 31, 2020 at 104.8% of par, beginning March 31, 2021 at 103.2% of par, beginning March 31, 2022 at 101.6% of par and beginning March 31, 2023 and thereafter at par. In addition, prior to the first date on which the Senior Notes are redeemable at the redemption prices noted above, the Company may also redeem some or all of the Senior Notes at a calculated make-whole premium, plus accrued and unpaid interest.

On August 9, 2018, the Company executed an amendment to the Indenture following the solicitation of consents from the requisite majorities of holders of each series of Senior Notes. The amendment permits a category of restricted payments at any time not to exceed the sum of $650.0 million, plus an additional $150.0 million per calendar year, commencing with calendar year 2019, with unused amounts in any calendar year carrying forward to and available for restricted payments in any subsequent calendar year. The Company paid consenting Senior Note holders $10.00 in cash per $1,000 principal amount of 2022 Notes and $30.00 in cash per $1,000 principal amount of 2025 Notes, which amounted to $19.8 million. Such consent payments were capitalized as additional debt issuance costs to be amortized over the respective terms of the Senior Notes. The Company also expensed $1.5 million of other fees associated with the amendment to "Interest expense" in the accompanying consolidated statements of operations during 2018.

During the fourth quarter of 2019, the Company made open-market purchases of $41.0 million of the 2022 Notes for $39.9 million, plus accrued interest. In connection with the purchases, the Company wrote off $1.3 million of debt issuance costs and charged $0.2 million to “Loss on early debt extinguishment.” The notes were subsequently canceled.

The Indenture contains customary conditions of default and imposes certain restrictions on the Company’s activities, including its ability to incur debt, incur liens, make investments, engage in fundamental changes such as mergers and dissolutions, dispose of assets, enter into transactions with affiliates and make certain restricted payments, such as cash dividends and share repurchases.

The Senior Notes rank senior in right of payment to any subordinated indebtedness and equally in right of payment with any senior indebtedness to the extent of the collateral securing that indebtedness. The Senior Notes are jointly and severally and fully and unconditionally guaranteed on a senior secured basis by substantially all of the Company’s material domestic subsidiaries and secured by first priority liens over (1) substantially all of the assets of the Company and the guarantors, except for certain excluded assets, (2) 100% of the capital stock of each domestic restricted subsidiary of the Company, (3) 100% of the non-voting capital stock of each first tier foreign subsidiary of the Company or a foreign subsidiary holding company and no more than 65% of the voting capital stock of each first tier foreign subsidiary of the Company or a foreign subsidiary holding company, (4) a legal charge of 65% of the voting capital stock and 100% of the non-voting capital stock of Peabody Investments (Gibraltar) Limited and (5) all intercompany debt owed to the Company or any guarantor, in each case, subject to certain exceptions. The obligations under the Senior Notes are secured on a *pari passu* basis by the same collateral securing the Credit Agreement (as defined below), subject to certain exceptions.

Credit Agreement

The Company entered into a credit agreement, dated as of April 3, 2017, among the Company, as borrower, Goldman Sachs Bank USA, as administrative agent, and other lenders party thereto (the Credit Agreement). The Credit Agreement originally provided for a $950.0 million senior secured term loan (the Senior Secured Term Loan), which was to mature in 2022 prior to the amendments described below.

Following the voluntary prepayments and amendments described below, the Credit Agreement provides for a $400.0 million first lien senior secured term loan, which bore interest at LIBOR plus 2.75% per annum as of December 31, 2019. During the years ended December 31, 2019 and 2018, the Company recorded interest expense of $22.2 million and $24.0 million, respectively, related to the Senior Secured Term Loan.

Proceeds from the Senior Secured Term Loan were received net of an original issue discount and deferred financing costs of $37.3 million that will be amortized over its term. The loan principal is payable in quarterly installments plus accrued interest through December 2024 with the remaining balance due in March 2025. The loan principal was voluntarily prepayable at 101% of the principal amount repaid if voluntarily prepaid prior to October 2018 (subject to certain exceptions, including prepayments made with internally generated cash) and is voluntarily prepayable at any time thereafter without premium or penalty. The Senior Secured Term Loan may require mandatory principal prepayments of up to 75% of Excess Cash Flow (as defined in the Credit Agreement) for any fiscal year if the Company’s Total Leverage Ratio (as defined in the Credit Agreement and calculated at December 31, net of any unrestricted cash), is greater than 2.00:1.00. The mandatory principal prepayment requirement is (i) 50% of Excess Cash Flow if the Company’s Total Leverage Ratio is less than or equal to 2.00:1.00 and greater than 1.50:1.00, (ii) 25% of Excess Cash Flow if the Company’s Total Leverage Ratio is less than or equal to 1.50:1.00 and greater than 1.00:1.00, or (iii) zero if the Company’s Total Leverage Ratio is less than or equal to 1.00:1.00. If required, mandatory prepayments resulting from Excess Cash Flows are payable within 100 days after the end of each fiscal year.The calculation of mandatory prepayments would be reduced commensurately by the amount of previous voluntary prepayments. In certain circumstances, the Senior Secured Term Loan also requires that Excess Proceeds (as defined in the Credit Agreement) of $10.0 million or greater from sales of Company assets be applied against the loan principal, unless such proceeds are reinvested within one year. The Senior Secured Term Loan also requires that any net insurance proceeds be applied against the loan principal, unless such proceeds are reinvested within one year.

The Credit Agreement contains customary conditions of default and imposes certain restrictions on the Company’s activities, including its ability to incur liens, incur debt, make investments, engage in fundamental changes such as mergers and dissolutions, dispose of assets, enter into transactions with affiliates, and make certain restricted payments, such as cash dividends and share repurchases. Obligations under the Credit Agreement are secured on a *pari passu* basis by the same collateral securing the Senior Notes.

Since entering into the Credit Agreement, the Company has repaid $557.0 million of the original $950.0 million loan principal amount on the Senior Secured Term Loan in various installments, including $546.0 million which was voluntarily prepaid. In September 2017, the Company entered into an amendment to the Credit Agreement which permitted the Company to add an incremental revolving credit facility in addition to the Company's ability to add one or more incremental term loan facilities under the Credit Agreement. The incremental revolving credit facility and/or incremental term loan facilities can be in an aggregate principal amount of up to $350.0 million plus additional amounts so long as the Company remains in compliance with Total Leverage Ratio requirements as set forth in the Credit Agreement. The Amendment also made available an additional restricted payment basket that permits additional repurchases, dividends or other distributions with respect to the Company's common and preferred Stock in an aggregate amount up to $450.0 million so long as the Company's Fixed Charge Coverage Ratio (as defined in the Credit Agreement) is at least 2.00:1.00 on a pro forma basis.

In April 2018, the Company entered into another amendment to the Credit Agreement which lowered the interest rate on the Senior Secured Term Loan to its current level of LIBOR plus 2.75% and eliminated an existing 1.0% LIBOR floor. The amendment also extended the maturity of the Senior Secured Term Loan by three years to 2025 and eliminated previous capital expenditure restriction covenants on both the Senior Secured Term Loan and the incremental revolving credit facility described below. In connection with this amendment, the Company voluntarily repaid $46.0 million of principal on the Senior Secured Term Loan.

During the fourth quarter of 2017, the Company entered into the incremental revolving credit facility (the Revolver) for an aggregate commitment of $350.0 million for general corporate purposes and paid aggregate debt issuance costs of $4.7 million. In September 2019, the Company entered into an amendment to the Credit Agreement which increased the aggregate commitment amount under the Revolver to $565.0 million and extended the maturity date on $540.0 million of the commitments from November 2020 to September 2023. The maturity date for the remaining $25.0 million commitment is November 2020. The Company incurred $5.7 million of additional debt issuance costs in connection with the amendment. The Revolver currently permits loans which bear interest at LIBOR plus 3.25%, as well as letters of credit which incur combined fees of 3.375% per annum. Unused capacity under the Revolver bears a commitment fee of 0.5% per annum. As a result of the amendment, such loans, letters of credit and unused capacity related to the $540.0 million of extended commitments will bear interest and incur fees at rates dependent upon the Company's First Lien Leverage Ratio (as defined in the Credit Agreement) beginning in 2020. The Revolver is also subject to a 2.00:1.00 Total Leverage Ratio requirement (as defined by the Credit Agreement), modified to limit unrestricted cash netting to $800.0 million.

To date, the Revolver has only been utilized for letters of credit, including $66.4 million outstanding at December 31, 2019. Such letters of credit were primarily in support of the Company's reclamation obligations, as further described in Note 25. "Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees." Availability under the Revolver was $498.6 million at December 31, 2019. During the years ended December 31, 2019 and 2018, the Company recorded interest expense and fees of $6.2 million and $7.2 million, respectively, related to the Revolver.

The Company's voluntary prepayments of $546.0 million of Senior Secured Term Loan principal and related amendments have been accounted for as a combination of partial debt extinguishments and debt modifications, depending upon the circumstances in each instance. During 2018, the Company charged a pro rata portion of debt issuance costs and original issue discount of $2.0 million to "Loss on early debt extinguishment" and expensed $0.9 million of financing costs and fees to "Interest expense" in the accompanying consolidated statements of operations, and capitalized an additional $1.0 million of deferred financing costs. During the period April 2 through December 31, 2017, the Company charged a pro rata portion of debt issuance costs and original issue discount of $20.9 million to "Loss on early debt extinguishment" and expensed $2.0 million of financing costs and fees to "Interest expense" in the accompanying consolidated statements of operations, and capitalized an additional $6.1 million of deferred financing costs.

Restricted Payments Under the Senior Notes and Credit Agreement

In addition to the $450.0 million restricted payment basket provided for under the September 2017 amendment, the Credit Amendment provides a builder basket for additional restricted payments subject to a maximum Total Leverage Ratio of 2.00:1.00 (as defined in the Credit Agreement).

In addition to the $650.0 million restricted payment basket, plus an additional $150.0 million per calendar year, provided under the August 2018 amendment, the Indenture provides a builder basket for restricted payments that is calculated based upon the Company's Consolidated Net Income, and is subject to a Fixed Charge Coverage Ratio of at least 2.25:1.00 (as defined in the Indenture).

Further, under both the Indenture and Credit Agreement, additional restricted payments are permitted through a $50.0 million general basket and an annual aggregate $25.0 million basket which allows dividends and common stock repurchases. The payment of dividends and purchases of common stock under this annual aggregate $25.0 million basket are permitted so long as the Company's Total Leverage Ratio would not exceed 1.25:1.00 on a pro forma basis (as defined in the Credit Agreement and Indenture).

Finance Lease Obligations

Refer to Note 15. "Leases" for additional information associated with the Company's finance leases, which pertain to the financing of mining equipment used in operations.

(15) Leases

The Company has operating and finance leases for mining and non-mining equipment, office space and certain other facilities under various non-cancellable agreements. Historically, the majority of the Company's leases have been accounted for as operating leases.

The Company and certain of its subsidiaries have guaranteed other subsidiaries' performance under various lease obligations. Certain lease agreements are subject to the restrictive covenants of the Company's credit facilities and include cross-acceleration provisions, under which the lessor could require remedies including, but not limited to, immediate recovery of the present value of any remaining lease payments. The Company typically agrees to indemnify lessors for the value of the property or equipment leased, should the property be damaged or lost during the course of the Company's operations. The Company expects that losses with respect to leased property, if any, may be covered by insurance (subject to deductibles). Aside from indemnification of the lessor for the value of the property leased, the Company's maximum potential obligations under its leases are equal to the respective future minimum lease payments, and the Company assumes that no amounts could be recovered from third parties. In this regard, the Company has recorded provisions amounting to $50.7 million related to the loss of leased equipment at its North Goonyella Mine as described in Note 22. "Other Events."

One of the Company's operating lease agreements for underground mining equipment in Australia entered into in 2013 requires contingent rent to be paid only if and when certain coal is mined at a specified margin as defined in the agreements. There was no contingent expense related to that arrangement for the periods listed below.

The components of lease expense during the year ended December 31, 2019 were as follows:

	Year Ended December 31, 2019
	(Dollars in millions)
Operating lease cost:	
Operating leases	$ 43.3
Short-term leases	49.7
Variable leases	19.1
Sublease income	(2.6)
Total operating lease cost	$ 109.5
Finance lease cost:	
Amortization of right-of-use assets	$ 15.3
Interest on lease liabilities	1.5
Total finance lease cost	$ 16.8

Supplemental balance sheet information related to leases at December 31, 2019 was as follows:

	December 31, 2019 (Dollars in millions)
Operating leases:	
Operating lease right-of-use assets	$ 82.4
Accounts payable and accrued expenses	$ 29.6
Operating lease liabilities, less current portion	52.8
Total operating lease liabilities	$ 82.4
Finance leases:	
Property, plant, equipment and mine development	$ 89.6
Accumulated depreciation	(45.9)
Property, plant, equipment and mine development, net	$ 43.7
Current portion of long-term debt	$ 14.3
Long-term debt, less current portion	0.9
Total finance lease liabilities	$ 15.2
Weighted average remaining lease term (years)	
Operating leases	3.8
Finance leases	0.6
Weighted average discount rate	
Operating leases	7.3%
Finance leases	6.0%

Supplemental cash flow information related to leases during the year ended December 31, 2019 was as follows:

	Year Ended December 31, 2019 (Dollars in millions)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for operating leases	$ 51.0
Operating cash flows for finance leases	1.5
Financing cash flows for finance leases	29.6
Right-of-use assets obtained in exchange for lease obligations:	
Operating leases	16.6
Finance leases	1.6

The Company's leases have remaining lease terms of 1 year to 11.3 years, some of which include options to extend the terms deemed reasonably certain of exercise. Maturities of lease liabilities were as follows:

Period Ending December 31,	Operating Leases	Finance Leases
	(Dollars in millions)	
2020	$ 33.7	$ 14.5
2021	23.1	0.6
2022	14.1	0.2
2023	12.2	0.1
2024	4.8	—
2025 and thereafter	7.2	—
Total lease payments	95.1	15.4
Less imputed interest	(12.7)	(0.2)
Total lease liabilities	$ 82.4	$ 15.2

Disclosures Related to Periods Prior to Adoption of ASU 2016-02 “Leases (Topic 842)”

Rental expense under operating leases, including expense related to short-term operating leases, was $158.0 million, $144.2 million and $57.0 million during the year ended December 31, 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively.

Future minimum lease and royalty payments as of December 31, 2018 were as follows:

Year Ending December 31,	Capital Leases	Operating Leases	Coal Lease and Royalty Obligations
		(Dollars in millions)	
2019	$ 28.2	$ 47.6	$ 5.4
2020	8.0	27.6	5.5
2021	0.4	15.9	5.6
2022	0.4	11.8	5.4
2023	0.5	12.1	5.5
2024 and thereafter	8.8	12.1	36.2
Total minimum lease payments	46.3	$ 127.1	$ 63.6
Less interest	6.3		
Present value of minimum capital lease payments	$ 40.0		

(16) Asset Retirement Obligations

Reconciliations of the Company's asset retirement obligations are as follows:

	December 31, 2019	December 31, 2018
	(Dollars in millions)	
Balance at beginning of period	$ 750.2	$ 691.1
Liabilities incurred or acquired	—	16.3
Liabilities settled or disposed	(47.7)	(57.8)
Accretion expense	54.1	48.5
Revisions to estimates	(4.3)	52.1
Balance at end of period	$ 752.3	$ 750.2
Less: Current portion (included in "Accounts payable and accrued expenses")	98.2	63.8
Noncurrent obligation (included in "Asset retirement obligations")	$ 654.1	$ 686.4
Balance at end of period — active locations	$ 525.4	$ 671.8
Balance at end of period — closed or inactive locations	$ 226.9	$ 78.4

During the year ended December 31, 2018, the Company acquired the Shoal Creek Mine and the related asset retirement obligations, as further discussed in Note 3. "Acquisition of Shoal Creek Mine." The changes in mine operations impacted reclamation estimates and are reflected in the asset retirement obligation asset and liability as of December 31, 2019 and 2018, respectively.

The credit-adjusted, risk-free interest rates utilized to estimate the Company's asset retirement obligations ranged from 9.24% for life of mines 3 years or less to 12.38% for life of mines greater than 20 years for both U.S. and Australia reclamation obligations at December 31, 2019 and ranged from 7.61% for life of mines 3 years or less to 11.54% for life of mines greater than 20 years for both U.S. and Australia reclamation obligations at December 31, 2018.

As of December 31, 2019 and 2018, the Company had $1,401.7 million and $1,317.0 million, respectively, in surety bonds and bank guarantees outstanding to secure reclamation obligations. Additionally, the Company had $106.1 million and $142.3 million, respectively, of letters of credit in support of reclamation obligations as of December 31, 2019 and 2018.

(17) Postretirement Health Care and Life Insurance Benefits

The Company currently provides health care and life insurance benefits to qualifying salaried and hourly retirees of its current and certain former subsidiaries and their dependents from benefit plans established by the Company. Plan coverage for health benefits is provided to future hourly and salaried retirees in accordance with the applicable plan document. Life insurance benefits are provided to future hourly retirees in accordance with the applicable labor agreement.

Net periodic postretirement benefit cost included the following components:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Service cost for benefits earned	$ 4.8	$ 8.2	$ 6.9	$ 2.3
Interest cost on accumulated postretirement benefit obligation	25.1	28.3	24.2	8.4
Expected return on plan assets	(0.5)	—	—	—
Amortization of prior service credit	(8.7)	—	—	(2.3)
Amortization of actuarial loss	—	—	—	5.5
Net actuarial loss (gain)	78.3	(128.4)	(22.0)	—
Net periodic postretirement benefit cost	$ 99.0	$ (91.9)	$ 9.1	$ 13.9

In connection with fresh start reporting, the Company made a policy election to prospectively record amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods.

The following includes pre-tax amounts recorded in “Accumulated other comprehensive income”:

	Successor		Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	January 1 through April 1, 2017
	(Dollars in millions)		
Prior service credit arising during year	$ —	$ (51.7)	$ —
Amortization:			
Actuarial loss	—	—	(5.5)
Prior service credit	8.7	—	2.3
Total recorded in “Accumulated other comprehensive income”	$ 8.7	$ (51.7)	$ (3.2)

The Company amortizes prior service credit over an amortization period of the average remaining service period to full eligibility for participating employees (4.9 years and 5.9 years at January 1, 2020 and 2019, respectively). Prior to April 2, 2017, the Company amortized actuarial gain and loss using a 0% corridor with an amortization period that covered the average remaining service period to full eligibility for participating employees (10.3 years at January 1, 2017). The estimated prior service credit that will be amortized from accumulated other comprehensive income into net periodic postretirement benefit cost during the year ending December 31, 2020 is $8.7 million.

The following table sets forth the plans’ funded status reconciled with the amounts shown in the consolidated balance sheets:

	December 31,	
	2019	2018
	(Dollars in millions)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of period	$ 595.4	$ 783.3
Service cost	4.8	8.2
Interest cost	25.1	28.3
Participant contributions	2.3	0.5
Plan amendments	—	(51.7)
Benefits paid	(47.7)	(44.8)
Actuarial loss (gain)	80.0	(128.4)
Accumulated postretirement benefit obligation at end of period	659.9	595.4
Change in plan assets:		
Fair value of plan assets at beginning of period	15.0	—
Actual return on plan assets	2.2	—
Employer contributions	62.4	59.3
Participant contributions	2.3	0.5
Benefits paid and administrative fees (net of Medicare Part D reimbursements)	(47.7)	(44.8)
Fair value of plan assets at end of period	34.2	15.0
Funded status at end of period	(625.7)	(580.4)
Less: Current portion (included in “Accounts payable and accrued expenses”)	32.3	32.7
Noncurrent obligation (included in “Accrued postretirement benefit costs”)	$ (593.4)	$ (547.7)

During October 2018, the Company announced an amendment to its postretirement health care benefit plan that, after December 31, 2018, (a) limits eligibility for retiree medical allowances based upon attainment of certain age and service criteria at December 31, 2018, (b) reduces the annual retiree medical allowance benefits earned by eligible employees and (c) establishes maximum limits on the amount eligible employees may earn and annual benefit payments. Employees with existing retiree medical allowance balances that lost continuing eligibility due to the amendment were awarded one-time discretionary contributions to their respective employee retirement accounts based upon years of service.

The impact of the amendment on future benefits reduced the Company's accumulated postretirement benefit obligation by $51.7 million. Of that amount, $50.2 million was attributable to the annual benefits and the maximum balance limits and $1.5 million was attributable to the limitation of eligibility based on age and service criteria. The reduction in liability was recorded with an offsetting balance in accumulated other comprehensive income, net of a deferred tax provision, of $44.6 million, which is being amortized to earnings over an average remaining service period to full eligibility for participating employees of 5.9 years.

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	December 31,	
	2019	2018
Discount rate	3.40%	4.35%
Measurement date	December 31, 2019	December 31, 2018

The weighted-average assumptions used to determine net periodic benefit cost during each period were as follows:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
Discount rate	4.35%	3.70%	4.10%	4.15%
Expected long-term return on plan assets	5.00%	—%	—%	—%
Measurement date	December 31, 2018	December 31, 2017	April 1, 2017	December 31, 2016

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results. Effective January 1, 2020 the Company increased its expected rate of return on plan assets from 5.00% to 7.00% reflecting the impact of the Company's asset allocation and capital market expectations.

The accumulated postretirement benefit obligation exceeded plan assets for all plans as of December 31, 2019 and 2018. The accumulated postretirement benefit obligation for all plans was $659.9 million and $595.4 million as of December 31, 2019 and 2018, respectively.

The following presents information about the assumed health care cost trend rate:

	Year Ended December 31,	
	2019	2018
Pre-Medicare:		
Health care cost trend rate assumed for next year	6.75%	6.55%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2023	2023
Post-Medicare:		
Health care cost trend rate assumed for next year	6.35%	6.15%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2023	2023

Assumed health care cost trend rates have a significant effect on the expense and liability amounts reported for health care plans. A one-percentage-point change in the assumed health care cost trend would have the following effects for the year ended December 31, 2019:

	One Percentage-Point Increase		One Percentage-Point Decrease	
	(Dollars in millions)			
Effect on total service and interest cost components	$	2.5	$	(2.3)
Effect on total postretirement benefit obligation	$	57.3	$	(50.9)

Plan Assets

The Company has established two Voluntary Employees Beneficiary Association (VEBA) trusts to pre-fund a portion of benefits for non-represented and represented retirees. Assets of the Peabody Investments Corp. Non-Represented Retiree VEBA Trust (the Non-Represented Trust) are invested in accordance with the investment policy established by the Peabody VEBA Retirement Committee after consultation with outside investment advisors and actuaries. The asset allocation strategy for the Non-Represented trust is 50% in equity and 50% in fixed income assets, which are designed to balance the needs of having growth and stability in the portfolio. This asset strategy may vary over time based on changes in the status of the Non-Represented Plan, the Company's risk posture and other factors. The Peabody Holding Company LLC Represented Retiree VEBA Trust (the Represented Trust) is unfunded at December 31, 2019 and 2018.

A financial instrument's level within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation techniques and inputs used for investments measured at fair value, including the general classification of such investments pursuant to the valuation hierarchy.

U.S. equity securities: The Non-Represented Trust invests in U.S. equity securities for growth and diversification. Investment vehicles include various domestic large-cap publicly traded common stocks and mutual funds. All common stocks are traded on a national securities exchange and are valued at quoted market prices in active markets and accordingly classified within Level 1 of the valuation hierarchy. The mutual funds are traded on a national securities exchange in an active market, are valued using daily publicly quoted net asset value (NAV) prices and accordingly classified within Level 1 of the valuation hierarchy.

International equity securities. The Non-Represented Trust invests in international equity securities for growth and diversification. Investment vehicles include various international publicly traded common stocks, exchange traded funds and mutual funds. All common stocks are traded on a national securities exchange and are valued at quoted market prices in active markets and accordingly classified within Level 1 of the valuation hierarchy. The exchange traded funds and mutual funds are traded on a national securities exchange in an active market, are valued using daily publicly quoted NAV prices and accordingly classified within Level 1 of the valuation hierarchy.

Corporate bonds. The Non-Represented Trust invests in corporate bonds for diversification, volatility reduction of equity securities and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly investment-grade corporate bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. Corporate bonds are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the bonds are not traded on a national securities exchange.

U.S. government securities. The Non-Represented Trust invests in U.S. government securities for diversification, volatility reduction of equity securities and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly U.S. government bonds, notes, agency securities and municipal bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. If fair value is based on quoted prices in active markets and traded on a national securities exchange, U.S. government securities are classified within the Level 1 valuation hierarchy; otherwise, U.S. government securities are classified within the Level 2 valuation hierarchy.

Cash funds. The Non-Represented Trust invests in cash funds to manage liquidity resulting from payment of participant benefits and certain administrative fees. The investment consists of a U.S. Government money market fund which is classified within the Level 1 valuation hierarchy.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. The inputs or methodologies used for valuing investments are not necessarily an indication of the risk associated with investing in those investments.

The following tables present the fair value of assets in the Non-Represented Trust by asset category and by fair value hierarchy:

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
U.S. equity securities	$ 13.0	$ —	$ —	$ 13.0
International equity securities	4.0	—	—	4.0
Corporate bonds	—	9.2	—	9.2
U.S. government securities	2.6	4.5	—	7.1
Cash funds	0.9	—	—	0.9
Total assets at fair value	$ 20.5	$ 13.7	$ —	$ 34.2

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Cash funds	$ 15.0	$ —	$ —	$ 15.0
Total assets at fair value	$ 15.0	$ —	$ —	$ 15.0

Contributions

Annual contributions to the Non-Represented Trust are discretionary. During the year ended December 31, 2019, the Company made a pre-funding contribution of $17.0 million to the Non-Represented Trust.

Estimated Future Benefit Payments

The following benefit payments (net of retiree contributions), which reflect expected future service, as appropriate, are expected to be paid by the Company:

	Postretirement Benefits
	(Dollars in millions)
2020	$ 46.1
2021	46.0
2022	45.6
2023	44.9
2024	44.1
Years 2025-2029	205.8

(18) Pension and Savings Plans

One of the Company’s subsidiaries, Peabody Investments Corp. (PIC), sponsors a defined benefit pension plan covering certain U.S. salaried employees and eligible hourly employees at certain PIC subsidiaries (the Peabody Plan). A subsidiary of PIC also has a defined benefit pension plan covering eligible employees who are represented by the UMWA under the Western Surface Agreement (the Western Plan). Prior to April 2, 2017, PIC also sponsored an unfunded supplemental retirement plan to provide senior management with benefits in excess of limits under the federal tax law (collectively, the Pension Plans).

Effective May 31, 2008, the Peabody Plan was frozen in its entirety for both participation and benefit accrual purposes. The Company adopted an enhanced savings plan contribution structure in lieu of benefits formerly accrued under the Peabody Plan. In November 2017, the Company purchased a group annuity contract from an insurance company to pay future pension benefits to approximately 1,950 retirees and beneficiaries of the Peabody Plan. As a result of this transaction, the Company settled $71.4 million of its pension obligation, paid from plan assets, and recorded a settlement charge of $2.1 million during the period April 2 through December 31, 2017.

Net periodic pension (benefit) cost included the following components:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Service cost for benefits earned	$ 2.0	$ 2.3	$ 1.6	$ 0.6
Interest cost on projected benefit obligation	33.5	31.4	28.0	9.7
Expected return on plan assets	(31.4)	(42.8)	(33.5)	(11.0)
Amortization of prior service cost	—	—	—	0.1
Amortization of net actuarial losses	—	—	—	6.3
Settlement charge	—	—	2.1	—
Net actuarial (gain) loss	(16.6)	4.2	(23.5)	—
Net periodic pension (benefit) cost	$ (12.5)	$ (4.9)	$ (25.3)	$ 5.7

In connection with fresh start reporting, the Company made a policy election to prospectively record amounts attributable to actuarial valuation changes currently in earnings rather than recording such amounts within accumulated other comprehensive income and amortizing to expense over applicable time periods.

The following includes pre-tax amounts recorded in “Accumulated other comprehensive income”:

	Predecessor
	January 1 through April 1, 2017
	(Dollars in millions)
Amortization:	
Net actuarial loss	$ (6.3)
Prior service cost	(0.1)
Total recorded in “Accumulated other comprehensive income”	$ (6.4)

Prior to April 2, 2017, the Company amortized actuarial gain and loss using a 5% corridor with a five-year amortization period.

The following summarizes the change in benefit obligation, change in plan assets and funded status of the Pension Plans:

	December 31, 2019	December 31, 2018
	(Dollars in millions)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$ 795.9	$ 874.6
Service cost	2.0	2.3
Interest cost	33.5	31.4
Benefits paid	(55.6)	(55.1)
Actuarial loss (gain)	78.0	(57.3)
Projected benefit obligation at end of period	853.8	795.9
Change in plan assets:		
Fair value of plan assets at beginning of period	764.8	776.6
Actual return on plan assets	126.0	(18.7)
Employer contributions	20.0	62.0
Benefits paid	(55.6)	(55.1)
Fair value of plan assets at end of period	855.2	764.8
Funded status at end of period	$ 1.4	$ (31.1)
Amounts recognized in the consolidated balance sheets:		
Noncurrent asset (included in “Investments and other assets”)	$ 13.4	$ —
Noncurrent obligation (included in “Other noncurrent liabilities”)	(12.0)	(31.1)
Net amount recognized	$ 1.4	$ (31.1)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows:

	December 31, 2019	December 31, 2018
Discount rate	3.40%	4.35%
Measurement date	December 31, 2019	December 31, 2018

The weighted-average assumptions used to determine net periodic pension (benefit) cost during each period were as follows:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
Discount rate	4.35%	3.70%	4.10%	4.15%
Expected long-term return on plan assets	4.20%	5.65%	5.90%	5.90%
Measurement date	December 31, 2018	December 31, 2017	April 1, 2017	December 31, 2016

The expected rate of return on plan assets is determined by taking into consideration expected long-term returns associated with each major asset class based on long-term historical ranges, inflation assumptions and the expected net value from active management of the assets based on actual results. Effective January 1, 2020, the Company lowered its expected rate of return on plan assets from 4.20% to 3.60% reflecting the impact of the Company’s asset allocation and capital market expectations.

The plan assets exceeded the projected benefit obligation and the accumulated benefit obligation for the Peabody Plan as of December 31, 2019. The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for the Western Plan as of December 31, 2019. The projected benefit obligation and the accumulated benefit obligation exceeded plan assets for all plans as of December 31, 2018. The accumulated benefit obligation for all plans was $853.8 million and $795.9 million as of December 31, 2019 and 2018, respectively.

Assets of the Pension Plans

Assets of the PIC Master Trust (the Master Trust) are invested in accordance with investment guidelines established by the Peabody Plan Retirement Committee and the Peabody Western Plan Retirement Committee (collectively, the Retirement Committees) after consultation with outside investment advisors and actuaries.

The asset allocation targets have been set with the expectation that the assets of the Master Trust will be managed with an appropriate level of risk to fund each Pension Plan's expected liabilities. To determine the appropriate target asset allocations, the Retirement Committees consider the demographics of each Pension Plan's participants, the funded status of each Pension Plan, the business and financial profile of the Company and other associated risk preferences. These allocation targets are reviewed by the Retirement Committees on a regular basis and revised as necessary. As a result of discretionary contributions made in recent years, the Pension Plans have become nearly fully funded and therefore, as of December 31, 2019 and 2018, the Master Trust investment portfolio reflected the Company's target asset mix of 100% fixed income investments. Master Trust assets also include investments in various real estate holdings through limited partnerships representing approximately less than 1% and 1% of total Master Trust assets as of December 31, 2019 and 2018, respectively. The Retirement Committees' intention is to liquidate these real estate holdings when allowable per the terms of the limited partnership agreements. Generally, dissolution and liquidation of the limited partnerships is required before the Master Trust's real estate holdings can be liquidated and is estimated to occur at various times through 2021.

Assets of the Master Trust are under management by third-party investment managers, which are selected and monitored by the Retirement Committees. Specific investment guidelines have been established by the Retirement Committees for each major asset class including performance benchmarks, allowable and prohibited investment types and concentration limits. In general, investment guidelines do not permit leveraging the assets held in the Master Trust. However, investment managers may employ various strategies and derivative instruments in establishing overall portfolio characteristics consistent with the guidelines and investment objectives established by the Retirement Committees for their portfolios. Fixed income investment guidelines only allow for exchange-traded derivatives if the investment manager deems the derivative vehicle to be more attractive than a similar direct investment in an underlying cash market or to manage the duration of the fixed income portfolio.

A financial instrument's level within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation techniques and inputs used for investments measured at fair value, including the general classification of such investments pursuant to the valuation hierarchy.

Corporate bonds. The Master Trust invests in corporate bonds for diversification and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly investment-grade corporate bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. Corporate bonds are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the bonds are not traded on a national securities exchange.

U.S. government securities. The Master Trust invests in U.S. government securities for diversification and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly U.S. government bonds, agency securities and municipal bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. If fair value is based on quoted prices in active markets and traded on a national securities exchange, U.S. government securities are classified within the Level 1 valuation hierarchy; otherwise, U.S. government securities are classified within the Level 2 valuation hierarchy.

International government securities. The Master Trust invests in international government securities for diversification and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominantly non-U.S. government bonds. Fair value for these securities is provided by a third-party pricing service that utilizes various inputs such as benchmark yields, reported trades, broker/dealer quotes, issuer spreads and benchmark securities as well as other relevant economic measures. International government securities are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the bonds are not traded on a national securities exchange.

Asset-backed securities. The Master Trust invests in asset-backed securities for diversification and to provide a hedge to interest rate movements affecting liabilities. Investment types are predominately mortgage-backed securities. Asset-backed securities are classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the investments are not traded on a national securities exchange.

Commercial paper. The Master Trust invests in commercial paper of U.S. corporations to manage liquidity resulting from payment of participant benefits and certain administrative fees. Commercial paper is classified within the Level 2 valuation hierarchy since fair value inputs are derived prices in active markets and the investments are not traded on a national securities exchange.

Cash funds. The Master Trust invests in cash funds to manage liquidity resulting from payment of participant benefits and certain administrative fees. Investment vehicles primarily include a non-interest bearing cash fund with an earnings credit allowance feature, various exchange-traded derivative instruments consisting of futures and interest rate swap agreements used to manage the duration of certain liability-hedging investments. The non-interest bearing cash fund is classified within the Level 1 valuation hierarchy. Exchange traded derivatives, such as options and futures, for which market quotations are readily available, are valued at the last reported sale price or official closing price on the primary market or exchange on which they are traded and are classified within the Level 1 valuation hierarchy.

Real estate interests. The Master Trust invests in real estate interests for diversification. Investments in real estate represent interests in several limited partnerships, which invest in various real estate properties. Interests in real estate are valued using various methodologies, including independent third party appraisals; fair value measurements are not developed by the Company. For some investments, little market activity may exist and determination of fair value is then based on the best information available in the circumstances. This involves a significant degree of judgment by taking into consideration a combination of internal and external factors. Accordingly, interests in real estate are classified within the Level 3 valuation hierarchy. Some limited partnerships issue dividends to their investors in the form of cash distributions that the Pension Plans invest elsewhere within the Master Trust.

Private mutual funds. The Master Trust invests in mutual funds for growth and diversification. Investment vehicles include an institutional fund that holds a diversified portfolio of long-duration corporate fixed income investments (Corporate Bond Fund). The Corporate Bond Fund is not traded on a national securities exchange and is valued at NAV, the practical expedient to estimate fair value.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. The inputs or methodologies used for valuing investments are not necessarily an indication of the risk associated with investing in those investments.

The following tables present the fair value of assets in the Master Trust by asset category and by fair value hierarchy:

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Corporate bonds	$ —	$ 598.3	$ —	$ 598.3
U.S. government securities	135.9	19.0	—	154.9
International government securities	—	18.2	—	18.2
Asset-backed securities	—	3.4	—	3.4
Cash funds	33.2	—	—	33.2
Real estate interests	—	—	4.1	4.1
Total assets at fair value	$ 169.1	$ 638.9	$ 4.1	812.1
Assets measured at net asset value practical expedient (1)				
Private mutual funds				43.1
Total plan assets				$ 855.2

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Corporate bonds	$ —	$ 466.1	$ —	$ 466.1
U.S. government securities	181.5	17.4	—	198.9
International government securities	—	12.4	—	12.4
Commercial paper	—	2.1	—	2.1
Cash funds	38.4	—	—	38.4
Real estate interests	—	—	6.2	6.2
Total assets at fair value	$ 219.9	$ 498.0	$ 6.2	724.1
Assets measured at net asset value practical expedient (1)				
Private mutual funds				40.7
Total plan assets				$ 764.8

(1) In accordance with Accounting Standards Update 2015-07, investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of assets of the plans.

The table below sets forth a summary of changes in the fair value of the Master Trust's Level 3 investments:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
Balance, beginning of period	$ 6.2	$ 11.8	$ 13.8	$ 14.1
Realized (losses) gains	(1.0)	2.6	—	0.6
Unrealized gains (losses) relating to investments still held at the reporting date	1.4	(2.6)	2.2	(0.6)
Purchases, sales and settlements, net	(2.5)	(5.6)	(4.2)	(0.3)
Balance, end of period	$ 4.1	$ 6.2	$ 11.8	$ 13.8

Contributions

Annual contributions to qualified plans are made in accordance with minimum funding standards and the Company's agreement with the Pension Benefit Guaranty Corporation. Funding decisions also consider certain funded status thresholds defined by the Pension Protection Act of 2006 (generally 80%). As of December 31, 2019, the Company's qualified plans are expected to be at or above the Pension Protection Act thresholds. Minimum funding standards are legislated by ERISA and are modified by pension funding stabilization provisions included in the Moving Ahead for Progress in the 21st Century Act of 2012, the Highway and Transportation Funding Act of 2014 and the Bipartisan Budget Act of 2015. Based upon minimum funding requirements, the Company is not required to make any payments to its qualified pension plans; however, during the year ended December 31, 2019, the Company made a discretionary contribution of $20.0 million to one of its qualified pension plans.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in connection with the Company's benefit obligation:

	Pension Benefits
	(Dollars in millions)
2020	$ 59.6
2021	59.3
2022	58.8
2023	59.5
2024	57.1
Years 2025-2029	268.0

Defined Contribution Plans

The Company sponsors employee retirement accounts under two 401(k) plans for eligible U.S. employees. The Company matches voluntary contributions to each plan up to specified levels. The expense for these plans was $27.8 million, $30.3 million, $25.5 million and $5.5 million for the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively. A performance contribution feature in one of the plans allows for additional discretionary contributions from the Company. There was no performance contribution granted for the year ended December 31, 2019. Prior performance contributions of $8.9 million and $8.5 million were paid during the years ended December 31, 2019 and 2018, respectively. There were no performance contributions paid during the period April 2 through December 31, 2017 or the period January 1 through April 1, 2017.

Superannuation

The Company makes superannuation contributions for eligible Australia employees in accordance with the employer contribution rate set by the Government of Australia. The expense related to these contributions was $26.5 million, $31.6 million, $19.9 million and $6.1 million for the years ended December 31, 2019 and 2018, the period April 2 through December 31, 2017 and the period January 1 through April 1, 2017, respectively. A performance contribution feature allows for additional discretionary contributions from the Company. There was no performance contribution granted for the year ended December 31, 2019. Prior performance contributions of approximately $3 million were paid during both of the years ended December 31, 2019 and 2018. There were no discretionary performance contributions paid during the period April 2 through December 31, 2017 or the period January 1 through April 1, 2017.

(19) Stockholders' Equity

Successor Company

Common Stock

In accordance with the Company's Fourth Amended and Restated Certificate of Incorporation, the Company has 450.0 million authorized shares of Common Stock, par value $0.01 per share. Holders of Common Stock are entitled to one vote per share on all matters to be voted upon by the stockholders. The holders of Common Stock do not have cumulative voting rights in the election of directors. Holders of Common Stock are entitled to receive ratably dividends if, as and when dividends are declared from time to time by the Board out of funds legally available for that purpose, after payment of dividends required to be paid on any outstanding preferred stock or series common stock. Upon dissolution, liquidation or winding up of the Company, the holders of Common Stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and subject to the right of holders of any outstanding preferred stock or series common stock. The Common Stock has no preemptive or conversion rights and is not subject to further calls or assessment by the Company. There are no redemption or sinking fund provisions applicable to the Common Stock.

The following table summarizes Common Stock activity during the periods presented below:

	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017
		(In millions)	
Shares outstanding at the beginning of the period	110.4	105.2	70.9
Shares issued for preferred share conversions	—	25.5	33.8
Shares issued for warrant conversions	—	—	6.2
Shares issued for vested restricted stock units	1.5	1.1	0.1
Shares issued for disputed claims	—	0.1	—
Shares repurchased	(15.0)	(21.5)	(5.8)
Shares outstanding at the end of the period	96.9	110.4	105.2

Preferred Stock

The Board is authorized to issue up to 100.0 million shares of preferred stock, par value $0.01 per share. On the Effective Date, 50.0 million shares of the preferred stock were designated as Series A Convertible Preferred Stock. On January 31, 2018, the remaining outstanding shares of Series A Convertible Preferred Stock were converted into shares of Common Stock.

The following table summarizes the Series A Convertible Preferred Stock activity during the periods presented below:

	Year Ended December 31, 2018	April 2 through December 31, 2017
	(In millions)	
Shares outstanding at the beginning of the period	13.5	30.0
Shares converted to Common Stock	(13.5)	(17.2)
Shares issued for payable in-kind preferred stock dividends	—	0.7
Shares outstanding at the end of the period	—	13.5

The shares of Series A Convertible Preferred Stock retained the status of authorized but unissued shares of preferred stock following the conversion and accordingly, the Company has 100.0 million authorized shares of preferred stock. The Board can determine the terms and rights of each series, including whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company and whether the shares of the series will be convertible into shares of any other class or series, or any other security, of the Company or any other corporation. The Board may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of preferred stock as of December 31, 2019.

Series Common Stock

The Board is authorized to issue up to 50.0 million shares of series common stock, par value $0.01 per share. The Board can determine the terms and rights of each series, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate of the series, redemption or sinking fund provisions, conversion terms, prices and rates and amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company and whether the shares of the series will be convertible into shares of any other class or series, or any other security, of the Company or any other corporation. The Board may also determine restrictions on the issuance of shares of the same series or of any other class or series, and the voting rights (if any) of the holders of the series. There were no outstanding shares of series common stock as of December 31, 2019.

Treasury Stock

Share repurchases. The Board has authorized a share repurchase program, as amended, to allow repurchases of up to $1.5 billion of the outstanding shares of the Company's common stock and/or preferred stock (Repurchase Program). Repurchases may be made from time to time at the Company's discretion. The specific timing, price and size of purchases will depend on the share price, general market and economic conditions and other considerations, including compliance with various debt agreements as they may be amended from time to time. The Repurchase Program does not have an expiration date and may be discontinued at any time. Through December 31, 2019, the Company repurchased 41.5 million shares of its Common Stock for $1,340.3 million (14.6 million shares for $329.9 million during the year ended December 31, 2019; 21.1 million shares for $834.7 million during the year ended December 31, 2018; and 5.8 million shares for $175.7 million during the period April 2 through December 31, 2017), which included commissions paid of $0.8 million. As of December 31, 2019, there was $160.5 million available for repurchase under the Repurchase Program. No additional repurchases are currently planned.

On August 14, 2018, Peabody Energy Corporation entered into a share repurchase agreement (the Share Repurchase Agreement) by and among the Company and its related parties, Elliott Associates, LP, Liverpool Limited Partnership and Sprayberry Investments Inc. to repurchase 7.2 million shares of the Company's common stock for an aggregate purchase price of approximately $300 million, which is included in the total amount of repurchases noted above. Pursuant to the Share Repurchase Agreement, the purchase price per share of $41.82 represented a 1.7% discount from the closing sale price of the common stock on the New York Stock Exchange on August 13, 2018. The repurchase transaction was made in conjunction with the Company's existing share repurchase program and closed on August 21, 2018.

Shares relinquished. The Company routinely allows employees to relinquish Common Stock to pay estimated taxes upon the vesting of restricted stock units and the payout of performance units that are settled in Common Stock under its equity incentive plans. The number of shares of Common Stock relinquished was 0.4 million for both the periods ended December 31, 2019 and 2018. The value of the Common Stock tendered by employees was based upon the closing price on the dates of the respective transactions.

Predecessor Company

In accordance with the Plan and as previously disclosed, each share of the Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, was extinguished, canceled and discharged, and each such share, option or warrant had no further force or effect as of the Effective Date. Furthermore, all of the Company's equity award agreements under prior incentive plans, and the awards granted pursuant thereto, were extinguished, canceled and discharged and had no further force or effect as of the Effective Date.

(20) Share-Based Compensation

Successor Company

The Company has established the Peabody Energy Corporation 2017 Incentive Plan (the 2017 Incentive Plan) for employees, non-employee directors and consultants that allows for the issuance of share-based compensation in various forms including options (including non-qualified stock options and incentive stock options), stock appreciation rights, restricted stock, restricted stock units, deferred stock, performance units, dividend equivalents and cash incentive awards. Under the 2017 Incentive Plan, approximately 14 million shares of the Company's Common Stock were reserved for issuance. As of December 31, 2019, there are approximately 8.9 million shares of the Company's Common Stock available for grant.

Share-Based Compensation Expense and Cash Flows

The Company's share-based compensation expense is recorded in "Operating costs and expenses" and "Selling and administrative expenses" in the consolidated statements of operations. Cash received by the Company upon the exercise of stock options is reflected as a financing activity in the consolidated statements of cash flows. Share-based compensation expense and cash flow amounts were as follows:

	Successor		
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017
	(Dollars in millions)		
Share-based compensation expense	$ 38.3	$ 34.9	$ 21.8
Tax benefit	—	—	—
Share-based compensation expense, net of tax benefit	$ 38.3	$ 34.9	$ 21.8
Cash received upon the exercise of stock options	—	—	—
Write-off tax benefits related to share-based compensation	—	—	—

As of December 31, 2019, the total unrecognized compensation cost related to nonvested awards was $27.7 million, net of taxes, which is expected to be recognized over 2.5 years with a weighted-average period of 0.6 years.

Deferred Stock Units

During the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017, the Company granted deferred stock units to each of the non-employee members of the Board. The fair value of these units is equal to the market price of the Company's Common Stock at the date of grant. These deferred stock units generally vest on a monthly basis over 12 months and are settled in Common Stock three years after the date of grant.

Restricted Stock Units

On the Effective Date, the Company granted restricted stock units under the 2017 Incentive Plan and the terms of the relevant restricted stock unit agreement to all employees, including its executive officers (the Emergence Awards). The Emergence Awards granted to the Company's executive officers generally will vest ratably on each of the first three anniversaries of the Effective Date, subject to, among other things, each such executive officer's continued employment with the Company. The Emergence Awards will become fully vested upon each such executive officer's termination of employment by the Company and its subsidiaries without Cause or by the executive for Good Reason (each, as defined in the 2017 Incentive Plan or award agreement) or due to a termination of employment with the Company and its subsidiaries by reason of death or Disability (as defined in the 2017 Incentive Plan or award agreement). In order to receive the Emergence Awards, the executive officers were required to execute restrictive covenant agreements protecting the Company's interests.

The Company grants restricted stock units to certain senior management and non-senior management employees. For units granted to both senior and non-senior management employees containing only service conditions, the fair value of the award is equal to the market price of the Company's Common Stock at the date of grant. Units granted to senior and non-senior management employees vest at various times (none of which exceed three years) in accordance with the underlying award agreement. Compensation cost for both senior and non-senior management employees is recognized on a straight-line basis over the requisite service period. The payouts for active grants awarded during the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017 will be settled in the Company's Common Stock.

A summary of restricted stock unit activity is as follows:

	Year Ended December 31, 2019		Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2018	2,641,087	$	24.87
Granted	664,899		29.75
Vested	(1,401,268)		23.40
Forfeited	(198,693)		30.96
Nonvested at December 31, 2019	1,706,025	$	26.89

The total fair value at grant date of restricted stock units granted during the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017 was $19.8 million, $18.2 million and $79.8 million, respectively.

The restricted stock units receive dividend equivalent units (DEUs) upon payment of cash dividends to holders of Common Stock. DEUs vest subject to the same vesting requirements as the underlying restricted stock unit award. As of December 31, 2019, there were approximately 176,000 nonvested DEUs. The total fair value of restricted stock units and DEUs vested was $40.3 million, $46.2 million and $0.9 million during the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017, respectively.

Performance Units

Performance units are typically granted annually in January and vest over a three-year measurement period and are primarily limited to senior management personnel. The performance units are usually subject to the achievement of goals based on the following conditions: three-year return on invested capital and environmental reclamation (performance condition). In addition, the payout of the performance units can be increased or decreased by up to 25% of the award based on three-year stock price performance compared to a custom peer group (market condition). There were no performance units granted during the period April 2 through December 31, 2017. Awards granted during the years ended December 31, 2019 and 2018 will be settled in the Company's Common Stock.

A summary of performance unit activity is as follows:

	Year Ended December 31, 2019	Weighted Average Remaining Contractual Life
Nonvested at December 31, 2018	206,630	2.0
Granted	264,918	
Vested	—	
Forfeited	(44,942)	
Nonvested at December 31, 2019	426,606	1.6

As of December 31, 2019, no performance units had vested.

The performance units receive DEUs upon payment of cash dividends to holders of Common Stock. DEUs vest subject to the same vesting requirements as the underlying performance unit award. As of December 31, 2019, there were approximately 44,000 nonvested DEUs

The performance condition awards were valued utilizing the grant date fair values of the Company's Common Stock adjusted for dividends foregone during the vesting period. The market condition awards were valued utilizing a Monte Carlo simulation model which incorporates the total stockholder return hurdles set for each grant. The assumptions used in the valuations for grants were as follows:

	Year Ended December 31,	
	2019	2018
Risk-free interest rate	2.44%	2.24%
Expected volatility	48.81%	57.75%
Dividend yield	—%	—%

Predecessor Company

In accordance with the Plan and as previously disclosed, each share of the Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, were extinguished, canceled and discharged, and each such share, option or warrant had no further force or effect as of the Effective Date. Furthermore, all of the Company's equity award agreements under prior incentive plans, and the awards granted pursuant thereto, were extinguished, canceled and discharged and had no further force or effect as of the Effective Date.

Share-Based Compensation Expense and Cash Flows

The Predecessor Company's share-based compensation expense was recorded in "Selling and administrative expenses" in the consolidated statements of operations. Cash received by the Predecessor Company upon the exercise of stock options and when employees purchased stock under the employee stock purchase plans was reflected as a financing activity in the consolidated statements of cash flows. Share-based compensation expense and cash flow amounts were as follows:

	Predecessor
	January 1 through April 1, 2017
	(Dollars in millions)
Share-based compensation expense - equity classified awards	$ 1.9
Tax benefit	—
Share-based compensation expense, net of tax benefit	$ 1.9
Cash received upon the exercise of stock options and from employee stock purchases	—
Write-off tax benefits related to share-based compensation	—

(21) Accumulated Other Comprehensive (Loss) Income

The following table sets forth the after-tax components of accumulated other comprehensive (loss) income and changes thereto:

	Foreign Currency Translation Adjustment	Net Actuarial Loss Associated with Postretirement Plans and Workers' Compensation Obligations	Prior Service Credit (Cost) Associated with Postretirement Plans	Cash Flow Hedges	Total Accumulated Other Comprehensive (Loss) Income
			(Dollars in millions)		
Predecessor Company					
December 31, 2016	$ (148.2)	$ (256.3)	$ 21.7	$ (94.2)	$ (477.0)
Reclassification from other comprehensive income to earnings	—	5.8	(1.4)	18.6	23.0
Current period change	5.5	—	—	—	5.5
Fresh start reporting adjustment	142.7	250.5	(20.3)	75.6	448.5
April 1, 2017	$ —	$ —	$ —	$ —	$ —
Successor Company					
Current period change	1.4	—	—	—	1.4
December 31, 2017	1.4	—	—	—	1.4
Current period change	(5.9)	—	44.6	—	38.7
December 31, 2018	(4.5)	—	44.6	—	40.1
Reclassification from other comprehensive income to earnings	—	—	(8.7)	—	(8.7)
Current period change	0.2	—	—	—	0.2
December 31, 2019	$ (4.3)	$ —	$ 35.9	$ —	$ 31.6

The components of accumulated other comprehensive income related to postretirement plans and workers' compensation obligations and cash flow hedges related to Predecessor periods were eliminated in accordance with fresh start reporting. As such, there were no amounts reclassified out of "Accumulated other comprehensive income" during the year ended December 31, 2018 or the period April 2 through December 31, 2017. The following table provides additional information regarding items reclassified out of "Accumulated other comprehensive income" into earnings during the periods presented below:

Details about accumulated other comprehensive loss components	Amount reclassified from accumulated other comprehensive loss (1) Successor Year Ended December 31, 2019	Predecessor January 1 through April 1, 2017	Affected line item in the consolidated statement of operations
	(Dollars in millions)		
Net actuarial loss associated with postretirement plans and workers' compensation obligations:			
Postretirement health care and life insurance benefits	$ —	$ (5.5)	Net periodic benefit costs, excluding service cost
Defined benefit pension plans	—	(6.3)	Net periodic benefit costs, excluding service cost
Workers' compensation amortization	—	2.7	Net periodic benefit costs, excluding service cost
	—	(9.1)	Total before income taxes
	—	3.3	Income tax benefit
	$ —	$ (5.8)	Total after income taxes
Prior service credit (cost) associated with postretirement plans:			
Postretirement health care and life insurance benefits	$ 8.7	$ 2.3	Net periodic benefit costs, excluding service cost
Defined benefit pension plans	—	(0.1)	Net periodic benefit costs, excluding service cost
	8.7	2.2	Total before income taxes
	—	(0.8)	Income tax provision
	$ 8.7	$ 1.4	Total after income taxes
Cash flow hedges:			
Foreign currency cash flow hedge contracts	$ —	$ (16.6)	Operating costs and expenses
Fuel and explosives commodity swaps	—	(11.0)	Operating costs and expenses
Insignificant items	—	(0.1)	
	—	(27.7)	Total before income taxes
	—	9.1	Income tax benefit
	$ —	$ (18.6)	Total after income taxes

(1) Presented as gains (losses) in the consolidated statements of operations.

Comprehensive loss differed from net loss by the amount of unrealized gain or loss resulting from valuation changes of the Company's cash flow hedges (see Note 9. "Derivatives and Fair Value Measurements" for information related to the Company's cash flow hedges), the change in actuarial loss and prior service cost of postretirement plans and workers' compensation obligations (see Note 17. "Postretirement Health Care and Life Insurance Benefits," Note 18. "Pension and Savings Plans" and Note 6. "Discontinued Operations" for information related to the Company's postretirement and pension plans) and foreign currency translation adjustment related to the Company's investments in Middlemount, whose functional currency is the Australian dollar. The values of the Company's cash flow hedging instruments were primarily affected by the U.S. dollar/Australian dollar exchange rate and changes in the prices of certain coal and diesel fuel products.

(22) Other Events

United Wambo Joint Venture with Glencore

In December 2019, after receiving the requisite regulatory and permitting approvals, the Company formed an unincorporated joint venture with Glencore plc (Glencore), in which the Company holds a 50% interest, to combine the existing operations of the Company's Wambo Open-Cut Mine in Australia with the adjacent coal reserves of Glencore's United Mine. The Company will proportionally consolidate the entity based upon its economic interest. Glencore will manage the mining operations of the joint venture (United Wambo Joint Venture).

Both parties contributed mining tenements and other assets upon formation. The Company accounted for its interest in the United Wambo Joint Venture at fair value and recognized a gain of $48.1 million, which was classified in "Gain on formation of United Wambo Joint Venture" in the accompanying consolidated statements of operations during the year ended December 31, 2019. The gain represents the difference between the fair value of the Company's interest in the joint venture, $63.7 million, and the carrying value of the Company's net assets contributed upon formation, $15.6 million. The fair value of the Company's interest in the joint venture is based on applying the income and cost valuation methods to the combined mining tenements and includes a provision for the estimated fair value of related asset retirement obligations.

PRB Colorado Joint Venture with Arch

On June 18, 2019, the Company entered into a definitive implementation agreement (the Implementation Agreement) with Arch, to establish a joint venture that will combine the respective Powder River Basin and Colorado operations of Peabody and Arch. Pursuant to the terms of the Implementation Agreement, Peabody will hold a 66.5% economic interest in the joint venture and Arch will hold a 33.5% economic interest. The Company expects to proportionally consolidate the entity based upon its economic interest. Governance of the joint venture will be overseen by the joint venture's board of managers, which will be comprised of Peabody and Arch representatives with voting powers proportionate with the companies' economic interests, with the exception of certain specified matters which will require supermajority approval. Peabody will manage the operations of the joint venture, subject to the supervision of the joint venture's board of managers.

Formation of the joint venture is subject to customary closing conditions, including the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, the receipt of certain other required regulatory approvals and the absence of injunctions or other legal restraints preventing the formation of the joint venture. The proposed joint venture is progressing through the U.S. Federal Trade Commission regulatory review process and the Company expects a decision in the first quarter, which would result in the clearance to form the joint venture or litigation to block its execution. In September 2019, the Company amended its Credit Agreement to expressly permit formation of the joint venture and is exploring various alternatives under the Indenture governing the Senior Notes. At such time as control over the existing operations is exchanged, the Company will account for its interest in the combined operations at fair value, which could result in a significant loss.

North Goonyella

The Company's North Goonyella Mine in Queensland, Australia experienced a fire in a portion of the mine during September 2018 and mining operations have been suspended since then. No mine personnel were physically harmed by the September 2018 events. On November 13, 2018, the Queensland Mine Inspectorate (QMI) initiated an investigation into the events that occurred at the mine to determine the cause of the event, assess the response to it and make recommendations to reduce the possibility of future incidents and improve response.

During the first quarter of 2019, the Company completed segmenting of the mine into multiple zones to facilitate a phased reventilation and re-entry of the mine. The Company commenced reventilation of the first zone of the mine during the second quarter of 2019 and subsequently re-entered the area in the third quarter. Following these activities and a detailed review and assessment of North Goonyella, the Company determined that due to the time, cost and required regulatory approach to ventilate and re-enter the rest of the mine, the Company will not pursue attempts to access certain portions of the mine through existing mine workings, but instead will move to the southern panels. The Company is currently in discussions with the QMI regarding ventilation and re-entry of the second zone of the current mine configuration. In 2020, the Company is commencing a commercial process for North Goonyella in conjunction with the existing mine development. The process comes in response to expressions of interest from potential strategic partners and other producers. Commercial outcomes could include a strategic financial partner, joint venture structure or complete sale of North Goonyella.

During the year ended December 31, 2018, the Company recorded $58.0 million in containment and idling costs related to the events at North Goonyella and a provision of $66.4 million for expected equipment losses. As work progressed and more information became available, the Company recorded an additional $111.5 million in containment and idling costs and an additional provision of $83.2 million related to equipment losses during the year ended December 31, 2019. The combined provision includes $50.7 million for the estimated cost to replace leased equipment, $45.6 million related to the cost of Company-owned equipment, $39.7 million related to unrecoverable longwall panel development and $13.6 million of other charges, which represents the best estimate of loss based on the assessments made at December 31, 2019.

In the event that no future mining occurs at the North Goonyella Mine or the Company is unable to find a commercial alternative, the Company may record additional charges for the remaining carrying value of the North Goonyella Mine of up to approximately $300 million. Incremental exposures above the aforementioned include take-or-pay obligations and other costs associated with idling or closing the mine.

In March 2019, the Company entered into an insurance claim settlement agreement with its insurers and various re-insurers under a combined property damage and business interruption policy and recorded a $125 million insurance recovery, the maximum amount available under the policy above a $50 million deductible. The Company has collected the full amount of the recovery.

On April 30, 2019, Peabody (Bowen) Pty Ltd entered into an option exercise and release agreement with Yancoal Technology Development Pty Ltd pursuant to which Peabody (Bowen) Pty Ltd exercised an option to acquire from Yancoal Technology Development Pty Ltd the longwall mining equipment used under license at the North Goonyella Mine for $54.2 million, which was consistent with what the Company recorded as a provision for equipment losses for the related impaired assets.

Divestitures and Other Transactions

The Company's Kayenta Mine closed during August 2019 upon termination of its coal supply agreement with the Navajo Generating Station (NGS) in Arizona. The NGS was the sole customer of the Kayenta Mine and the coal supply agreement provided for consideration to the Company related to its post-mining obligations for retiree healthcare and reclamation costs. A cumulative portion of such consideration, $53.5 million, was held in trust and released to the Company upon termination. During the fourth quarter of 2019, the parties entered into a settlement agreement to finalize such consideration for an additional $78.5 million payable to the Company. Of this amount, $35.4 million was receivable at December 31, 2019 and $16.3 million of such receivable was collected in January 2020.

In June 2018, Peabody entered into an agreement to sell approximately 23 million tonnes of metallurgical coal resources adjacent to its Millennium Mine to Stanmore Coal Limited for approximately $22 million. The sale was completed in July 2018 and the Company recorded a gain of $20.5 million which is included within "Net gain on disposals" in the accompanying consolidated statements of operations for the year ended December 31, 2018.

On February 6, 2018, the Company sold its 50% interest in the Red Mountain Joint Venture (RMJV) with BHP Billiton Mitsui Coal Pty Ltd (BMC) for $20.0 million and recorded a gain of $7.1 million, which is included within "Net gain on disposals" in the accompanying consolidated statements of operations for the year ended December 31, 2018. RMJV operated the coal handling and preparation plant utilized by the Company's Millennium Mine. BMC assumed the reclamation obligations and other commitments associated with the assets of RMJV. The Millennium Mine had continued usage of the coal handling and preparation plant and the associated rail loading facility until the end of 2019 via a coal washing take-or-pay agreement with BMC.

In January 2018, Peabody entered into an agreement to sell its share in certain surplus land assets in Queensland's Bowen Basin to Pembroke Resources South Pty Ltd for approximately $37 million Australian dollars, net of transaction costs. The necessary approval of the Australian Foreign Investment Review Board to complete the transaction was received on March 29, 2018, satisfying all the conditions precedent to the sale, and the Company recorded a gain of $20.6 million, which is included within "Net gain on disposals" in the accompanying consolidated statements of operations for the year ended December 31, 2018.

On November 28, 2017, the Company paid $3.0 million for a third-party's assumption of all rights and obligations related to a guarantee liability recorded pursuant to a 2007 transaction wherein the Company purchased approximately 345 million tons of coal reserves and surface lands in the Illinois Basin. In conjunction with the 2007 purchase, the Company agreed to guarantee certain reclamation and bonding commitments of an affiliate of the seller. The Company extinguished its associated $34.2 million liability upon completion of the 2017 transaction and recorded a gain of $31.2 million which is included within "Net gain on disposals" in the accompanying consolidated statements of operations for the period April 2 through December 31, 2017.

On November 27, 2017, the Company completed the sale of the majority of its Burton Mine and related infrastructure to the Lenton Joint Venture for $11.7 million. The Lenton Joint Venture assumed the reclamation obligations associated with the assets acquired in the sale. The transaction reduced the Company's asset retirement obligation by $40.5 million and reduced the amount of restricted cash held in support of such obligations by approximately $30 million. The Burton Mine, located in Queensland's Bowen Basin, entered a care, maintenance and rehabilitation phase in December 2016 and had no carrying value at the time of sale. In connection with the transaction, the Company recorded a gain of $52.2 million which is included within "Net gain on disposals" in the accompanying consolidated statements of operations for the period April 2 through December 31, 2017.

The Company had 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 March 31, 2017, the Company completed a sale of its interest in Dominion Terminal Associates to Contura Terminal, LLC and Ashland Terminal, Inc., both of which are partners of the Dominion Terminal Associates. The Company collected $20.5 million in proceeds and recorded $19.7 million of gain on the sale, which was classified in "Net gain on disposals" in the consolidated statement of operations during the period January 1 through April 1, 2017.

In November 2016, the Company entered into a definitive share sale and purchase agreement (SPA) for the sale of all of its equity interest in Metropolitan Collieries Pty Ltd, the entity that owns the Metropolitan Mine in New South Wales, Australia and the associated interest in the Port Kembla Coal Terminal, to South32 Limited (South32). The SPA provided for a cash purchase price of $200.0 million and certain contingent consideration, subject to a customary working capital adjustment. South32 terminated the agreement in April 2017 after it was unable to obtain necessary approvals from the Australian Competition and Consumer Commission within the timeframe required under the SPA. As a result of the termination, the Company retained an earnest deposit posted by South32 which was recorded in "Revenues" in the accompanying consolidated statements of operations during the period April 2 through December 31, 2017.

In November 2015, the Company entered into a definitive agreement to sell its New Mexico and Colorado assets to Bowie Resource Partners, LLC (Bowie) in exchange for cash proceeds of $358 million and the assumption of certain liabilities. Bowie agreed to pay the Company a termination fee of $20 million (Termination Fee) in the event the Company terminated the agreement because Bowie failed to obtain financing and close the transaction. On April 12, 2016, Peabody terminated the agreement and demanded payment of the Termination Fee. Following a favorable judgment by the Bankruptcy Court, the Company collected the Termination Fee from Bowie. The Termination Fee is included in "Revenues" in the accompanying consolidated statements of operations during the period April 2 through December 31, 2017.

(23) Earnings per Share (EPS)

Basic EPS is computed based on the weighted average number of shares of common stock outstanding during the period. Diluted EPS is computed based on the weighted average number of shares of common stock plus the effect of dilutive potential common shares outstanding. As such, the Company includes the share-based compensation awards in its potentially dilutive securities. Dilutive securities are not included in the computation of loss per share when a company reports a net loss from continuing operations as the impact would be anti-dilutive.

During the periods which included the Company's Convertible Preferred Stock and the Predecessor Company's restricted stock awards, basic and diluted EPS were computed using the two-class method, which is an earnings allocation that determines EPS for each class of common stock and participating securities according to dividends declared and participation rights in undistributed earnings. The Company's Convertible Preferred Stock was considered a participating security because holders were entitled to receive dividends on an if-converted basis. The Predecessor Company's restricted stock awards were considered participating securities because holders were entitled to receive non-forfeitable dividends during the vesting term. The calculation of diluted EPS for the Predecessor Company also considered the impact of its Convertible Junior Subordinated Debentures due December 2066 (the Debentures). Diluted EPS assumes that participating securities are not executed or converted.

For all but the performance units, the potentially dilutive impact of the Company's share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation. For the performance units, their contingent features result in an assessment for any potentially dilutive common stock by using the end of the reporting period as if it were the end of the contingency period for all units granted. For further discussion of the Company's share-based compensation awards, see Note 20. "Share-Based Compensation."

Up to the time of cancellation, a conversion of the Debentures could have resulted in payment for any conversion value in excess of the principal amount of the Debentures in the Predecessor Company's common stock. For diluted EPS purposes, potential common stock was calculated based on whether the market price of the Predecessor Company's common stock at the end of each reporting period was in excess of the conversion price of the Debentures. The effect of the Debentures was excluded from the calculation of diluted EPS for all Predecessor periods presented herein because to do so would have been anti-dilutive for those periods.

The computation of diluted EPS excluded aggregate share-based compensation awards of approximately 1.9 million and 0.3 million for the year ended December 31, 2019 and the period January 1 through April 1, 2017, respectively, and less than 0.1 million for both the year ended December 31, 2018 and the period April 2 through December 31, 2017, because to do so would have been anti-dilutive for those periods. Because the potential dilutive impact of such share-based compensation awards is calculated under the treasury stock method, anti-dilution generally occurs when the exercise prices or unrecognized compensation cost per share of such awards are higher than the Company's average stock price during the applicable period. Anti-dilution also occurs when a company reports a net loss from continuing operations, and the dilutive impact of all share-based compensation awards are excluded accordingly.

The following illustrates the earnings allocation method utilized in the calculation of basic and diluted EPS:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(In millions, except per share amounts)			
EPS numerator:				
(Loss) income from continuing operations, net of income taxes	$ (188.3)	$ 645.7	$ 713.1	$ (195.5)
Less: Series A Convertible Preferred Stock dividends	—	102.5	179.5	—
Less: Net income attributable to noncontrolling interests	26.2	16.9	15.2	4.8
(Loss) income from continuing operations attributable to common stockholders, before allocation of earnings to participating securities	(214.5)	526.3	518.4	(200.3)
Less: Earnings allocated to participating securities	—	7.9	129.0	—
(Loss) income from continuing operations attributable to common stockholders, after allocation of earnings to participating securities (1)	(214.5)	518.4	389.4	(200.3)
Income (loss) from discontinued operations, net of income taxes	3.2	18.1	(19.8)	(16.2)
Less: Income (loss) from discontinued operations allocated to participating securities	—	0.3	(4.9)	—
Income (loss) from discontinued operations attributable to common stockholders, after allocation of earnings to participating securities	3.2	17.8	(14.9)	(16.2)
Net (loss) income attributable to common stockholders, after allocation of earnings to participating securities (1)	$ (211.3)	$ 536.2	$ 374.5	$ (216.5)
EPS denominator:				
Weighted average shares outstanding — basic	103.7	119.3	101.1	18.3
Impact of dilutive securities	—	1.7	1.4	—
Weighted average shares outstanding — diluted (2)	103.7	121.0	102.5	18.3
Basic EPS attributable to common stockholders:				
(Loss) income from continuing operations	$ (2.07)	$ 4.35	$ 3.85	$ (10.93)
Income (loss) from discontinued operations	0.03	0.15	(0.15)	(0.88)
Net (loss) income attributable to common stockholders	$ (2.04)	$ 4.50	$ 3.70	$ (11.81)
Diluted EPS attributable to common stockholders:				
(Loss) income from continuing operations	$ (2.07)	$ 4.28	$ 3.81	$ (10.93)
Income (loss) from discontinued operations	0.03	0.15	(0.14)	(0.88)
Net (loss) income attributable to common stockholders	$ (2.04)	$ 4.43	$ 3.67	$ (11.81)

(1) The reallocation adjustment for participating securities to arrive at the numerator to calculate diluted EPS was $0.1 million and $1.2 million for the year ended December 31, 2018 and the period April 2 through December 31, 2017, respectively.

(2) The two-class method assumes that participating securities are not exercised or converted. As such, weighted average diluted shares outstanding excluded 2.1 million shares and 33.5 million shares related to the participating securities for the year ended December 31, 2018, and the period April 2 through December 31, 2017, respectively.

In accordance with the Plan, each share of the Predecessor Company's common stock outstanding prior to the Effective Date, including all options and warrants to purchase such stock, was extinguished, canceled and discharged, and each such share, option or warrant has no further force or effect after the Effective Date. Furthermore, all of the Predecessor Company's equity award agreements under prior incentive plans, and the equity awards granted pursuant thereto, were extinguished, canceled and discharged and have no further force or effect after the Effective Date.

As of January 31, 2018, all 30.0 million shares of Convertible Preferred Stock issued upon the Effective Date had been converted into 59.3 million shares of Common Stock, which is inclusive of the shares that had been issued for the payable in-kind preferred stock dividends.

(24) Management — Labor Relations

On December 31, 2019, the Company had approximately 6,600 employees worldwide, including approximately 5,000 hourly employees; the employee amounts exclude employees that were employed at operations classified as discontinued operations. Approximately 42% of those hourly employees were represented by organized labor unions and were employed by mines that generated 19% of the Company's 2019 coal production from continuing operations. In the U.S., two mines are represented by an organized labor union. In Australia, the coal mining industry is unionized and the majority of hourly workers employed at the Company's Australian mining operations are members of trade unions. The Construction, Forestry, Maritime, Mining and Energy Union generally represents the Company's Australian subsidiaries' hourly production and engineering employees, including those employed through contract mining relationships. The Company believes labor relations with its employees are good. Should that condition change, the Company could experience labor disputes, work stoppages or other disruptions in production that could negatively impact the Company's results of operations and cash flows.

The following table presents the Company's active mining operations as of December 31, 2019 in which the employees are represented by organized labor unions:

Mine	Current Agreement Expiration Date
U.S.	
Kayenta (1)	September 2019
Shoal Creek (2)	April 2021
Australia	
Owner-operated mines:	
North Goonyella (3)	December 2018
Millennium (4)	March 2019
Wilpinjong (5)	May 2020
Moorvale (6)	June 2020
Metropolitan (7)	January 2021
Wambo Underground (8)	March 2021
Coppabella (9)	June 2021
Wambo Open-Cut (8)	March 2022

(1) Prior to its closure in 2019, hourly workers at the Company's Kayenta Mine in Arizona were represented by the UMWA under the Western Surface Agreement, which was effective through September 16, 2019. This agreement covered mostly now terminated hourly employees who generated approximately 3% of the Company's U.S. production during the year ended December 31, 2019. The Company is in negotiations with the UMWA for an agreement covering the hourly workers expected to be involved in mining reclamation.

(2) Hourly workers at the Company's Shoal Creek Mine in Alabama are represented by the UMWA under the Shoal Creek Wage Agreement, which is effective through April 1, 2021. This agreement covers approximately 11% of the Company's U.S. subsidiaries' hourly employees who generated approximately 1% of the Company's U.S. production during the year ended December 31, 2019. The Company acquired the Shoal Creek Mine on December 3, 2018, as further described in Note 3. "Acquisition of Shoal Creek Mine."

(3) Employees of the North Goonyella Mine operated under a separate labor agreement which expired in December 2018. Due to the idling of the mine, as further described in Note 22. "Other Events," hourly employees were terminated and there are no current negotiations for a new labor agreement.

(4) The current labor agreement for Millennium Mine expired in March 2019 and the Company has announced plans to close the mine in 2020. The Company, employees and unions agreed via a memorandum of understanding to an extension of the expired agreement through March 2020, and a new labor agreement will not be required. Hourly employees of this mine comprise approximately 1% of the Company's Australian subsidiaries' hourly employees, who generated approximately 2% of the Company's Australian production during the year ended December 31, 2019.

(5) The current Wilpinjong labor agreement for Wilpinjong Mine expires in May 2020. Hourly employees of this mine comprise approximately 25% of the Company's Australian subsidiaries' hourly employees, who generated approximately 54% of the Company's Australian production during the year ended December 31, 2019.

(6) Employees of the Company's Moorvale Mine operate on individual contracts underpinned by a non-union enterprise agreement. Employees are managed according to their individual contracts rather than the enterprise agreement. The current memorandum of understanding agreeing to a rollover of the existing enterprise agreement expires in June 2020. Hourly employees of this mine comprise approximately 14% of the Company's Australian subsidiaries' hourly employees, who generated approximately 6% of the Company's Australian production during the year ended December 31, 2019.

(7) Employees of the Company's Metropolitan Mine operate under a separate labor agreement, which expires in January 2021. There is also a deputy labor agreement which expires in April 2022. During 2019, the Company insourced the operation of the Metropolitan coal handling and preparation plant and the hourly employees are employed under a separate labor agreement that expires in May 2021. Hourly employees of this mine comprise approximately 14% of the Company's Australian subsidiaries' hourly employees, who generated approximately 6% of the Company's Australian production during the year ended December 31, 2019.

(8) Employees of the Wambo Open-Cut Mine operate under a separate enterprise agreement which will expire in March 2022. Negotiations for the new agreement concluded in the fourth quarter of 2019. There were market-related wage increases agreed over the three-year term of the new labor agreement. Employees of the Company's Wambo Underground Mine operate under a separate labor agreement. That agreement will expire in March 2021. The Wambo coal handling and preparation plant hourly employees are under a separate labor agreement that expires in December 2021. Hourly employees of these mines comprise approximately 24% of the Company's Australian subsidiaries' hourly employees, who generated approximately 22% of the Company's Australian production during the year ended December 31, 2019.

(9) Employees of the Company's Coppabella Mine operate under a separate enterprise agreement which expires in June 2021. Hourly employees of this mine comprise approximately 22% of the Company's Australian subsidiaries' hourly employees, who generated approximately 9% of the Company's Australian production during the year ended December 31, 2019.

(25) Financial Instruments, Guarantees With Off-Balance-Sheet Risk and Other Guarantees

In the normal course of business, the Company is a party to various guarantees and financial instruments that carry off-balance-sheet risk and are not reflected in the accompanying consolidated balance sheets. At December 31, 2019, such instruments included $1,609.2 million of surety bonds and bank guarantees and $200.5 million of letters of credit. Such financial instruments provide support for the Company's reclamation bonding requirements, lease obligations, insurance policies and various other performance guarantees. The Company periodically evaluates the instruments for on-balance-sheet treatment based on the amount of exposure under the instrument and the likelihood of required performance. The Company does not expect any material losses to result from these guarantees or off-balance-sheet instruments in excess of liabilities provided for in the accompanying consolidated balance sheets.

Reclamation Bonding

The Company is required to provide various forms of financial assurance in support of its mining reclamation obligations in the jurisdictions in which it operates. Such requirements are typically established by statute or under mining permits. Historically, such assurances have taken the form of third-party instruments such as surety bonds, bank guarantees, letters of credit, cash collateral held in restricted accounts, and self-bonding arrangements in the U.S. In connection with its emergence from the Chapter 11 Cases, the Company elected to utilize primarily a portfolio of surety bonds to support its U.S. obligations.

At December 31, 2019, the Company's asset retirement obligations of $752.3 million were supported by surety bonds of $1,401.7 million as well as letters of credit issued under the Company's receivables securitization program and Revolver amounting to $106.1 million.

Accounts Receivable Securitization

The Company entered into the Sixth Amended and Restated Receivables Purchase Agreement, as amended, dated as of April 3, 2017 (the Receivables Purchase Agreement) to extend the Company's receivables securitization facility previously in place and expand that facility to include certain receivables from the Company's Australian operations. The receivables securitization program (Securitization Program) is subject to customary events of default set forth in the Receivables Purchase Agreement. The Securitization Program provides for up to $250.0 million in funding accounted for as a secured borrowing, limited to the availability of eligible receivables, and may be secured by a combination of collateral and the trade receivables underlying the program, from time to time. Funding capacity under the Securitization Program may also be utilized for letters of credit in support of other obligations. During 2019, the Company entered into an amendment to the Securitization Program to extend its term through April 1, 2022 and reduce program fees.

Under the terms of the Securitization Program, the Company contributes the trade receivables of its participating subsidiaries on a revolving basis to P&L Receivables, its wholly-owned, bankruptcy-remote subsidiary, which then sells the receivables to unaffiliated banks. P&L Receivables retains the ability to repurchase the receivables in certain circumstances. The assets and liabilities of P&L Receivables are consolidated with Peabody, and the Securitization Program is treated as a secured borrowing for accounting purposes, but the assets of P&L Receivables will be used first to satisfy the creditors of P&L Receivables, not Peabody's creditors. The borrowings under the Securitization Program remain outstanding throughout the term of the agreement, subject to the Company maintaining sufficient eligible receivables, by continuing to contribute trade receivables to P&L Receivables, unless an event of default occurs.

At December 31, 2019, the Company had no outstanding borrowings and $132.7 million of letters of credit drawn under the Securitization Program. The letters of credit were primarily in support of portions of the Company's obligations for reclamation, workers' compensation and postretirement benefits. Availability under the Securitization Program, which is adjusted for certain ineligible receivables, was $45.0 million at December 31, 2019. The Company had no cash collateral requirement under the Securitization Program at either December 31, 2019 or 2018. The Company incurred fees associated with the Securitization Program of $5.5 million, $5.2 million and $5.3 million during the years ended December 31, 2019 and 2018 and the period April 2 through December 31, 2017, respectively, which have been recorded as "Interest expense" in the accompanying statements of operations. As it relates to the former receivables securitization facility in place prior to the Effective Date, the Company incurred interest expense of $2.0 million during the period January 1 through April 1, 2017.

Collateral Arrangements and Restricted Cash

The Company remits cash to certain regulatory authorities and other third parties as collateral for financial assurances associated with a variety of long-term obligations and commitments surrounding the mining, reclamation and shipping of its production. The Company had $323.1 million held by third parties related to such obligations at December 31, 2017. All such collateral was returned to the Company during the year ended December 31, 2018, largely as the result of replacing collateral balances with third-party surety bonding in Australia.

Other

The Company is the lessee under numerous equipment and property leases. It is common in such commercial lease transactions for the Company, as the lessee, to agree to indemnify the lessor for the value of the property or equipment leased, should the property be damaged or lost during the course of the Company's operations. The Company expects that losses with respect to leased property, if any, may be covered by insurance (subject to deductibles). The Company and certain of its subsidiaries have guaranteed other subsidiaries' performance under various lease obligations. Aside from indemnification of the lessor for the value of the property leased, the Company's maximum potential obligations under its leases are equal to the respective future minimum lease payments, and the Company assumes that no amounts could be recovered from third parties. In this regard, the Company recorded provisions of $0.3 million and $50.4 million during the years ended December 31, 2019 and 2018, respectively, for the loss of leased equipment at the North Goonyella Mine as described in Note 22. "Other Events."

The Company has provided financial guarantees under certain long-term debt agreements entered into by its subsidiaries and substantially all of the Company's U.S. subsidiaries provide financial guarantees under long-term debt agreements entered into by the Company. The maximum amounts payable under the Company's debt agreements are equal to the respective principal and interest payments.

(26) Commitments and Contingencies

Commitments

Unconditional Purchase Obligations

As of December 31, 2019, purchase commitments for capital expenditures were $39.7 million, all of which is obligated in the next year.

In Australia, the Company has generally secured the ability to transport coal through rail contracts and ownership interests in five east coast coal export terminals that are primarily funded through take-or-pay arrangements with terms ranging up to 23 years. In the U.S., the Company has entered into certain long-term coal export terminal agreements to secure export capacity through the Gulf Coast. As of December 31, 2019, these Australian and U.S. commitments under take-or-pay arrangements totaled $1.1 billion, of which approximately $116 million is obligated within the next year.

Contingencies

From time to time, the Company or its subsidiaries are involved in legal proceedings arising in the ordinary course of business or related to indemnities or historical operations. The Company believes it has recorded adequate reserves for these liabilities. The Company discusses its significant legal proceedings below, including ongoing proceedings and those that impacted the Company's results of operations for the periods presented.

Litigation Relating to the Chapter 11 Cases

Ad Hoc Committee. On March 22, 2017, a group of creditors (the Ad Hoc Committee) that held certain interests in the Company's prepetition indebtedness appealed the Bankruptcy Court's order confirming the Plan, requesting that the United States District Court for the Eastern District of Missouri (the District Court) reverse the Bankruptcy Court's confirmation of the Plan and the order approving the Private Placement Agreement and Backstop Commitment Agreement. On December 29, 2017, the District Court entered an order dismissing the Ad Hoc Committee's appeal, and, in the alternative, affirming the order confirming the Plan. On January 26, 2018, the Ad Hoc Committee appealed the District Court's order to the United States Court of Appeals for the Eighth Circuit (the Eighth Circuit). In its appeal, the Ad Hoc Committee asked the Eighth Circuit to award the Ad Hoc Committee members either unspecified damages or the right to buy an unspecified amount of Company stock at a discount. Oral argument on the appeal was held April 16, 2019, and the Eighth Circuit issued a unanimous opinion in Peabody's favor on August 9, 2019. The Ad Hoc Committee did not seek rehearing or petition the Supreme Court for certiorari by the deadline of November 7, 2019.

Litigation Relating to Continuing Operations

Peabody Monto Coal Pty Ltd, Monto Coal 2 Pty Ltd and Peabody Energy Australia PCI Pty Ltd (PEA-PCI). On October 1, 2007, a claim was made against Peabody Monto Coal Pty Ltd, a wholly-owned subsidiary of Macarthur Coal Limited (Macarthur) that is now a wholly-owned subsidiary of the Company, and Monto Coal 2 Pty Ltd, an equity accounted investee of Macarthur, now known as PEA-PCI. The claim, made by the minority interest holders in the joint venture, alleged that the Macarthur companies breached certain agreements by failing to develop a mine project. The claim was amended to assert that Macarthur also induced the alleged breach of the Monto Coal Joint Venture Agreement. The Company acquired Macarthur and its subsidiaries in 2011. The claim originally sought damages of up to $1.1 billion Australian dollars, plus interest and costs, but was amended in November 2019 to seek $18 million Australian dollars, plus interest and costs.

The Company asserted that the Macarthur companies were never under an obligation to develop the mine project because the project was not economically viable. A trial commenced in the Supreme Court of Queensland, Australia on April 8, 2019 and concluded on December 12, 2019. Before a decision was handed down, the parties reached a settlement to end the multi-year dispute, the terms of which included the Company (a) transferring its interests in Monto Coal 2 Pty Ltd, and therefore the Monto Coal Joint Venture, to the claimant; and (b) agreeing to use commercially reasonable efforts to transfer certain other assets to the claimant. These settlement terms are not expected to result in a material impact to the Company's financial accounts. As a result of the settlement, the parties filed a dismissal of the litigation on January 24, 2020.

County of San Mateo, County of Marin, City of Imperial Beach. The Company was named as a defendant, along with numerous other companies, in three nearly identical lawsuits brought by municipalities in California on July 17, 2017. The lawsuits seek to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels and seek compensatory and punitive damages in an amount to be proven at trial, attorneys' fees and costs, disgorgement of profits and equitable relief of abatement. The lawsuits primarily assert that the companies' products have caused a sea level rise that is damaging the plaintiffs. The complaints specifically alleged that the defendants' activities from 1965 to 2015 caused such damage. The Company filed a motion to enforce the Plan because it enjoins claims that arose before the effective date of the Plan. The motion to enforce was granted on October 24, 2017, and the Bankruptcy Court ordered the plaintiffs to dismiss their lawsuits against the Company. On November 26, 2017, the plaintiffs appealed the Bankruptcy Court's October 24, 2017 order to the District Court. On November 28, 2017, the plaintiffs sought a stay pending appeal from the Bankruptcy Court, which was denied on December 8, 2017. On December 19, 2017, the plaintiffs moved the District Court for a stay pending appeal. The District Court denied the stay request on September 20, 2018, and the plaintiffs have appealed that decision to the Eighth Circuit. On March 29, 2019, the District Court affirmed the Bankruptcy Court ruling enjoining the plaintiffs from proceeding with their lawsuits against the Company. That ruling likewise is being appealed. In the underlying cases pending in California, the U.S. District Court for the Northern District of California granted plaintiffs' motion for remand and decided the cases should be heard in state court. The defendants appealed the order granting remand to the Ninth Circuit and sought a stay of the U.S. District Court for the Northern District of California decision pending completion of the Ninth Circuit appeal. The U.S. District Court for the Northern District of California granted defendants' request for a stay pending completion of the Ninth Circuit appeal. The plaintiffs filed a motion to dismiss part of the appeal. The parties are now litigating at the Ninth Circuit whether a state or federal court should hear these lawsuits. Regardless of whether state court or federal court is the venue, the Company believes the lawsuits against it should be dismissed under enforcement of the Plan. The Company does not believe the lawsuits are meritorious and, if the lawsuits are not dismissed, the Company intends to vigorously defend them.

Other

At times, the Company becomes a party to other disputes, including those related to contract miner performance, claims, lawsuits, arbitration proceedings, regulatory investigations and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where the Company does business. Based on current information, the Company believes that such other pending or threatened proceedings are likely to be resolved without a material adverse effect on its financial condition, results of operations or cash flows.

(27) Summary of Quarterly Financial Information (Unaudited)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2019 and 2018 is presented below.

	Successor			
	Year Ended December 31, 2019			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$ 1,250.6	$ 1,149.0	$ 1,106.4	$ 1,117.4
Operating profit (loss)	184.5	79.5	(36.8)	(165.5)
Income (loss) from continuing operations, net of income taxes	133.3	42.9	(74.3)	(290.2)
Net income (loss)	129.9	39.5	(78.1)	(276.4)
Net income (loss) attributable to common stockholders	124.2	37.1	(82.8)	(289.8)
Basic EPS — continuing operations (1)	$ 1.18	$ 0.38	$ (0.77)	$ (3.12)
Diluted EPS — continuing operations (1)	$ 1.15	$ 0.37	$ (0.77)	$ (3.12)
Weighted average shares used in calculating basic EPS	108.5	107.0	102.2	97.3
Weighted average shares used in calculating diluted EPS	110.5	108.1	102.2	97.3

(1) EPS for the quarters may not sum to the amounts for the year as each period is computed on a discrete basis.

Operating profit for the first quarter of 2019 reflected $125.0 million related to insurance recoveries for property settlements resulting from the North Goonyella fire in September 2018. Operating loss for the fourth quarter 2019 reflected a $48.1 million gain on formation of the United Wambo Joint Venture as it relates to the difference between the fair value of Peabody's interest and the carrying value of the mining tenements and other assets contributed. Operating loss for the third and fourth quarter of 2019 reflected the favorable net impact associated with the final commercial negotiations for the Kayenta Mine of $14.0 million and $69.3 million, respectively. Operating loss for the third and fourth quarter of 2019 reflected $8.2 million and $11.8 million, respectively, in transactions costs related to the joint venture with Arch. Operating loss for the third and fourth quarter of 2019 reflected asset impairment charges of $20.0 million and $250.2 million, respectively, related to mines within the Midwestern U.S. Mining and Western U.S. mining segments, certain unallocated U.S. coal reserves and an investment in equity securities. Operating results for the first and fourth quarter reflected $24.7 million and $58.5 million related to the provision for North Goonyella equipment loss, respectively. Operating loss for the fourth quarter 2019 reflects $23.0 million in restructuring charges for workforce reductions. Operating results for the second and fourth quarters included income from equity affiliates of $9.7 million and $10.9 million, respectively, while third quarter results reflected a loss of $20.7 million resulting from suspended operations and change in mine plan. Results from continuing operations, net of income taxes for the first, second, third and fourth quarters of 2019 included steady interest expense of $35.8 million, $36.0 million, $35.4 million and $36.8 million, respectively, partially offset by interest income of $8.3 million, $7.2 million, $7.0 million and $4.5 million in the first, second, third and fourth quarters of 2019, respectively. Loss from continuing operations, net of income taxes for the fourth quarter of 2019 included an adjustment of $67.4 million related to net mark-to-market losses on actuarially determined liabilities.

	Successor			
	Year Ended December 31, 2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$ 1,462.7	$ 1,309.4	$ 1,412.6	$ 1,397.1
Operating profit	239.2	165.3	130.3	126.8
Income from continuing operations, net of income taxes	208.3	120.0	83.9	233.5
Net income	207.0	116.4	79.8	260.6
Net income attributable to common stockholders	106.6	113.7	71.5	252.6
Basic EPS — continuing operations (1)	$ 0.84	$ 0.94	$ 0.64	$ 1.99
Diluted EPS — continuing operations (1)	$ 0.83	$ 0.93	$ 0.63	$ 1.97
Weighted average shares used in calculating basic EPS	120.9	124.5	118.6	113.1
Weighted average shares used in calculating diluted EPS	123.2	126.0	120.3	114.7

(1) EPS for the quarters may not sum to the amounts for the year as each period is computed on a discrete basis.

Operating profit for the first and third quarter of 2018 reflected $30.6 million and $20.7 million of gains on disposal of assets, respectively, primarily driven by net gains on the sale of certain surplus land assets in Queensland's Bowen Basin and the sale of surplus coal resources associated with the Company's Millennium Mine of $20.6 million and $20.5 million, respectively. Operating profit for the third and fourth quarter of 2018 reflected $49.3 million and $17.1 million related to the provision for North Goonyella equipment loss, respectively. Operating profit for the first, second and third quarter of 2018 included steady income from equity affiliates of $22.0 million, $25.2 million and $17.2 million, respectively, due to favorable coal pricing at Middlemount. Operating profit for the fourth quarter of 2018 included acquisition costs related to the Shoal Creek Mine of $4.9 million. Income from continuing operations, net of income taxes for the first, second, third and fourth quarters of 2018 included steady interest expense of $36.3 million, $38.3 million, $38.2 million and $36.5 million respectively, partially offset by interest income of $7.2 million, $7.0 million, $10.1 million and $9.3 million in the first, second, third and fourth quarters of 2018, respectively. Income from continuing operations, net of income taxes for the first quarter of 2018 included a credit of $12.8 million for reorganization items, net due to a bankruptcy claims accrual adjustment in relation to the Company's emergence from the Chapter 11 Cases. Income from continuing operations, net of income taxes for the fourth quarter of 2018 reflected $125.5 million of net mark-to-market gains on actuarially determined liabilities.

(28) Segment and Geographic Information

The Company reports its results of operations primarily through the following reportable segments: Seaborne Thermal Mining, Seaborne Metallurgical Mining, Powder River Basin Mining, Midwestern U.S. Mining, Western U.S. Mining and Corporate and Other.

During the year ended December 31, 2019, the Cottage Grove Mine in the Midwestern U.S. Mining segment and the Kayenta Mine in the Western U.S. Mining segment shipped their final tons. The Company also announced the closures of the Wildcat Hills Underground and Somerville Central Mines in the Midwestern U.S. Mining segment, with both of those operations expecting to ship their final tons in 2020. Due to these changes, the Company will update its reportable segments beginning in the first quarter of 2020 to combine the Midwestern U.S. Mining segment with the Western U.S. Mining segment, which reflects the manner in which the chief operating decision maker (CODM) views the Company's businesses going forward for purposes of reviewing performance, allocating resources and assessing future prospects and strategic execution. Beginning the first quarter of 2020, the Company will report its results of operations primarily through the following reportable segments: Seaborne Thermal Mining, Seaborne Metallurgical Mining, Powder River Basin Mining, Other U.S. Thermal Mining and Corporate and Other.

The business of the Company's seaborne operating platform is primarily export focused with customers spread across several countries, with a portion of its thermal and metallurgical coal 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. The Company classifies its seaborne mines within the Seaborne Thermal Mining or Seaborne Metallurgical 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 Seaborne Thermal Mining segment is of a metallurgical grade. Similarly, a small portion of the coal mined by the Seaborne Metallurgical Mining segment is of a thermal grade. Additionally, the Company may market some of its metallurgical coal products as a thermal coal product from time to time depending on market conditions.

The Company's Seaborne Thermal Mining operations consist of mines in New South Wales, Australia. The mines in that segment utilize both surface and underground extraction processes to mine low-sulfur, high Btu thermal coal.

The Company's Seaborne Metallurgical Mining operations consist of mines in Queensland, Australia, one in New South Wales, Australia and one in Alabama. The mines in that segment utilize both surface and underground extraction processes 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 coal.

The principal business of the Company's thermal 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 relatively small portion sold as international exports as conditions warrant. The Company's Powder River Basin Mining operations consist of its 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). The Company's Midwestern U.S. Mining operations include its 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). The Company's Western U.S. Mining operations historically reflect the aggregation of its New Mexico, Arizona and Colorado mining operations. The mines in that segment are characterized by a mix of surface and underground mining extraction processes and coal with a mid-range sulfur content and Btu. Geologically, the Company's Powder River Basin Mining operations mine sub-bituminous coal deposits, its Midwestern U.S. Mining operations mine bituminous coal deposits and its Western U.S. Mining operations mine both bituminous and sub-bituminous coal deposits.

The Company's Corporate and Other segment includes selling and administrative expenses, including its technical and shared services functions, results from equity affiliates, corporate hedging activities, trading and brokerage activities, certain mining and export/transportation joint ventures, restructuring charges and activities associated with the optimization of its coal reserve and real estate holdings, minimum charges on certain transportation-related contracts, the closure of inactive mining sites and certain commercial matters.

The Company's CODM uses Adjusted EBITDA as the primary metric to measure the segments' operating performance. Adjusted EBITDA is a non-GAAP financial measure defined as (loss) income from continuing operations before deducting net interest expense, income taxes, asset retirement obligation expenses, 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 below. Management believes non-GAAP performance measures are used by investors to measure the Company's operating performance and lenders to measure the Company's ability to incur and service debt. 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.

Segment results for the year ended December 31, 2019 were as follows:

	Successor						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 971.7	$ 1,033.1	$ 1,228.7	$ 669.7	$ 639.7	$ 80.5	$ 4,623.4
Adjusted EBITDA	329.4	140.2	221.2	130.7	230.7	(215.1)	837.1
Additions to property, plant, equipment and mine development	42.1	143.4	42.8	35.9	18.1	3.1	285.4
Income from equity affiliates	—	—	—	—	—	(3.4)	(3.4)

Segment results for the year ended December 31, 2018 were as follows:

	Successor						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 1,099.2	$ 1,553.0	$ 1,424.8	$ 801.0	$ 592.0	$ 111.8	$ 5,581.8
Adjusted EBITDA	452.0	441.4	284.5	145.2	145.4	(89.2)	1,379.3
Additions to property, plant, equipment and mine development	66.6	88.7	81.0	46.6	13.9	4.2	301.0
Federal coal lease expenditures	—	—	—	—	0.5	—	0.5
Income from equity affiliates	—	—	—	—	—	(68.1)	(68.1)

Segment results for the period April 2 through December 31, 2017 were as follows:

	Successor						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 772.5	$ 1,221.0	$ 1,178.7	$ 592.3	$ 440.7	$ 47.4	$ 4,252.6
Adjusted EBITDA	306.6	414.9	278.8	124.4	131.8	(111.2)	1,145.3
Additions to property, plant, equipment and mine development	39.2	56.0	32.6	21.7	13.8	3.3	166.6
Income from equity affiliates	—	—	—	—	—	(49.0)	(49.0)

Segment results for the period January 1 through April 1, 2017 were as follows:

	Predecessor						
	Seaborne Thermal Mining	Seaborne Metallurgical Mining	Powder River Basin Mining	Midwestern U.S. Mining	Western U.S. Mining	Corporate and Other	Consolidated
	(Dollars in millions)						
Revenues	$ 224.8	$ 328.9	$ 394.3	$ 193.2	$ 149.7	$ 35.3	$ 1,326.2
Adjusted EBITDA	75.6	109.6	91.7	50.0	50.0	(35.6)	341.3
Additions to property, plant, equipment and mine development	2.3	5.2	19.3	2.8	3.1	0.1	32.8
Federal coal lease expenditures	—	—	—	—	0.5	—	0.5
Income from equity affiliates	—	—	—	—	—	(15.0)	(15.0)

Asset details are reflected at the division level only for the Company's mining segments and are not allocated between each individual segment as such information is not regularly reviewed by the Company's CODM. Further, some assets service more than one segment within the division and an allocation of such assets would not be meaningful or representative on a segment by segment basis.

Assets as of December 31, 2019 were as follows:

	Seaborne Mining	U.S. Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Total assets	$ 2,001.3	$ 3,044.8	$ 1,496.7	$ 6,542.8
Property, plant, equipment and mine development, net	1,610.9	2,776.9	291.3	4,679.1
Operating lease right-of-use assets	32.1	30.3	20.0	82.4

Assets as of December 31, 2018 were as follows:

	Seaborne Mining	U.S. Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Total assets	$ 2,044.6	$ 3,481.7	$ 1,897.4	$ 7,423.7
Property, plant, equipment and mine development, net	1,661.3	3,180.4	365.3	5,207.0

Assets as of December 31, 2017 were as follows:

	Seaborne Mining	U.S. Thermal Mining	Corporate and Other	Consolidated
	(Dollars in millions)			
Total assets	$ 2,339.6	$ 3,846.5	$ 1,995.1	$ 8,181.2
Property, plant, equipment and mine development, net	1,501.7	3,361.0	249.2	5,111.9

A reconciliation of consolidated (loss) income from continuing operations, net of income taxes to Adjusted EBITDA follows:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
	(Dollars in millions)			
(Loss) income from continuing operations, net of income taxes	$ (188.3)	$ 645.7	$ 713.1	$ (195.5)
Depreciation, depletion and amortization	601.0	679.0	521.6	119.9
Asset retirement obligation expenses	58.4	53.0	41.2	14.6
Gain on formation of United Wambo Joint Venture	(48.1)	—	—	—
Asset impairment	270.2	—	—	30.5
Provision for North Goonyella equipment loss	83.2	66.4	—	—
North Goonyella insurance recovery - equipment (1)	(91.1)	—	—	—
Changes in deferred tax asset valuation allowance and reserves and amortization of basis difference related to equity affiliates	(18.8)	(18.3)	(17.3)	(5.2)
Interest expense	144.0	149.3	119.7	32.9
Loss on early debt extinguishment	0.2	2.0	20.9	—
Interest income	(27.0)	(33.6)	(5.6)	(2.7)
Net mark-to-market adjustment on actuarially determined liabilities	67.4	(125.5)	(45.2)	—
Reorganization items, net	—	(12.8)	—	627.2
Gain on disposal of reclamation liability	—	—	(31.2)	—
Gain on disposal of Burton Mine assets	—	—	(52.2)	—
Break fees related to terminated asset sales	—	—	(28.0)	—
Unrealized (gains) losses on economic hedges	(42.2)	(18.3)	23.0	(16.6)
Unrealized (gains) losses on non-coal trading derivative contracts	(1.2)	0.7	1.5	—
Fresh start coal inventory revaluation	—	—	67.3	—
Fresh start take-or-pay contract-based intangible recognition	(16.6)	(26.7)	(22.5)	—
Income tax provision (benefit)	46.0	18.4	(161.0)	(263.8)
Total Adjusted EBITDA	$ 837.1	$ 1,379.3	$ 1,145.3	$ 341.3

(1) As described in Note 22. “Other Events,” the Company recorded a $125.0 million insurance recovery during the year ended December 31, 2019 related to losses incurred at its North Goonyella Mine. Of this amount, Adjusted EBITDA excludes an allocated amount applicable to total equipment losses recognized at the time of the insurance recovery settlement, which consisted of $24.7 million and $66.4 million recognized during the years ended December 31, 2019 and 2018, respectively. The remaining $33.9 million, applicable to incremental costs and business interruption losses, is included in Adjusted EBITDA for the year ended December 31, 2019.

The following table presents revenues as a percent of total revenue from external customers by geographic region:

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 2 through December 31, 2017	January 1 through April 1, 2017
U.S.	53.6%	47.8%	48.9%	55.2%
Japan	15.4%	10.1%	11.7%	11.4%
Taiwan	6.0%	8.1%	8.7%	5.7%
Australia	5.8%	6.6%	5.3%	4.2%
China	3.8%	5.9%	7.5%	5.6%
South Korea	2.9%	3.1%	1.1%	0.5%
India	1.2%	6.2%	6.7%	2.7%
Other	11.3%	12.2%	10.1%	14.7%
Total	100.0%	100.0%	100.0%	100.0%

The Company attributes revenue to individual countries based on the location of the physical delivery of the coal.

PEABODY ENERGY CORPORATION
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions(1)	Other	Balance at End of Period
	(Dollars in millions)					
Successor						
Year Ended December 31, 2019						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ 0.3	$ —	$ —	$ —	$ —	$ 0.3
Reserve for materials and supplies	0.2	8.9	—	(1.2)	—	7.9
Allowance for doubtful accounts	4.4	(4.4)	—	—	—	—
Tax valuation allowances	2,094.3	(29.8)	—	—	3.9	2,068.4
Year Ended December 31, 2018						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ —	$ 0.3	$ —	$ —	$ —	$ 0.3
Reserve for materials and supplies	0.6	0.5	—	(0.9)	—	0.2
Allowance for doubtful accounts	4.6	(0.2)	—	—	—	4.4
Tax valuation allowances	2,432.5	(275.0)	—	—	(63.2) (4)	2,094.3
April 2 through December 31, 2017						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ —	$ —	$ —	$ —	$ —	$ —
Reserve for materials and supplies	—	1.0	—	(0.4)	—	0.6
Allowance for doubtful accounts	—	4.6	—	—	—	4.6
Tax valuation allowances	3,288.4	(744.9)	—	—	(111.0) (3)	2,432.5
Predecessor						
January 1 through April 1, 2017						
Reserves deducted from asset accounts:						
Advance royalty recoupment reserve	$ 7.8	$ —	$ (7.4) (2)	$ (0.4)	$ —	$ —
Reserve for materials and supplies	5.6	0.5	(6.1) (2)	—	—	—
Allowance for doubtful accounts	13.1	—	(12.8) (2)	(0.3)	—	—
Tax valuation allowances	4,037.5	(777.2)	28.1 (2)	—	—	3,288.4

(1) Reserves utilized, unless otherwise indicated.

(2) Fresh start reporting adjustments.

(3) Release of valuation allowance primarily related to carrybacks of U.S. net operating losses.

(4) Includes the impact of the decrease in Australian dollar exchange rates, partially offset by the impact of final attribute reduction adjustments in the U.S.

EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K.

Exhibit No.	Description of Exhibit
2.1	Debtors' Second Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code as revised March 15, 2017 (Incorporated by reference to Exhibit 2.2 of the Registrant's Current Report on Form 8-K, filed March 20, 2017).
2.2	Order Confirming Debtors' Second Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code on March 17, 2017 (Incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K, filed March 20, 2017).
2.3	Asset Purchase Agreement, dated as of September 20, 2018, by and between Drummond Company, Inc. and Peabody Southeast Mining, LLC, and, for certain limited purposes, Peabody Energy Corporation (Incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K, filed September 24, 2018).
2.4	Implementation Agreement, dated as of June 18, 2019, between Peabody Energy Corporation and Arch Coal, Inc. (Incorporated by reference to Exhibit 2.1 of the Registrant's Current Report on Form 8-K/A filed on June 19, 2019).
3.1	Fourth Amended and Restated Certificate of Incorporation of the Registrant (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed April 3, 2017).
3.2	Amended and Restated By-Laws of the Registrant (Incorporated by reference to Exhibit 3.3 of the Registrant's Current Report on Form 8-K filed April 3, 2017).
4.1	Specimen of stock certificate representing the Registrant's common stock, $.01 par value (Incorporated by reference to Exhibit 4.13 to Amendment No. 4 to the Registrant's Form S-1 Registration Statement No. 333-55412, filed May 1, 2001).
4.2	Indenture, dated as of February 15, 2017, between Peabody Securities Finance Corporation and Wilmington Trust, National Association, as Trustee, governing 6.000% Senior Secured Notes due 2022 and 6.375% Senior Secured Notes due 2025 (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K, filed February 15, 2017).
4.3	First Supplemental Indenture, dated as of April 3, 2017, among the Registrant, Peabody Securities Finance Corporation, the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.3 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
4.4	Second Supplemental Indenture, dated as of May 7, 2018, among the Registrant, NGS Acquisition Corp., LLC, and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.4 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2018).
4.5	Third Supplemental Indenture, dated as of August 9, 2018, between the Registrant and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2018).
4.6	Fourth Supplemental Indenture, dated as of December 7, 2018, among the Registrant, Peabody Southeast Mining, LLC, and Wilmington Trust, National Association, as trustee (Incorporated by reference to Exhibit 4.6 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2018).
4.7†	Description of Securities.
10.1	Federal Coal Lease WYW0321779: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.3 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.2	Federal Coal Lease WYW119554: North Antelope/Rochelle Mine (Incorporated by reference to Exhibit 10.4 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.3	Federal Coal Lease WYW5036: Rawhide Mine (Incorporated by reference to Exhibit 10.5 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.4	Federal Coal Lease WYW3397: Caballo Mine (Incorporated by reference to Exhibit 10.6 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.5	Federal Coal Lease WYW83394: Caballo Mine (Incorporated by reference to Exhibit 10.7 of the Registrant's Form S-4 Registration Statement No. 333-59073, filed July 14, 1998).
10.6	Federal Coal Lease WYW136142 (Incorporated by reference to Exhibit 10.8 of Amendment No. 1 to the Registrant's Form S-4 Registration Statement No. 333-59073, filed September 8, 1998).
10.7	Royalty Prepayment Agreement by and among Peabody Natural Resources Company, Gallo Finance Company and Chaco Energy Company, dated September 30, 1998 (incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
10.8	Federal Coal Lease WYW154001: North Antelope Rochelle South (Incorporated by reference to Exhibit 10.68 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).

10.9	Federal Coal Lease WYW150210: North Antelope Rochelle Mine (Incorporated by reference to Exhibit 10.8 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
10.10	Federal Coal Lease WYW151134 effective May 1, 2005: West Roundup (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005).
10.11	Federal Coal Lease Readjustment WYW78633: Caballo (Incorporated by reference to Exhibit 10.24 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.12	Transfer by Assignment and Assumption of Federal Coal Lease WYW172657: Caballo West (Incorporated by reference to Exhibit 10.25 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.13	Federal Coal Lease WYW176095: Porcupine South (Incorporated by reference to Exhibit 10.26 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.14	Federal Coal Lease WYW173408: North Porcupine (Incorporated by reference to Exhibit 10.27 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.15	Federal Coal Lease WYW172413: School Creek (Incorporated by reference to Exhibit 10.28 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012).
10.16	Separation Agreement, Plan of Reorganization and Distribution, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.17	Tax Separation Agreement, dated October 22, 2007, between the Registrant and Patriot Coal Corporation (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.18	Coal Act Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.19	Salaried Employee Liabilities Assumption Agreement, dated October 22, 2007, among Patriot Coal Corporation, Peabody Holding Company, LLC, Peabody Coal Company, LLC and the Registrant (Incorporated by reference to Exhibit 10.5 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.20	Coal Supply Agreement, dated October 22, 2007, between Patriot Coal Sales LLC and COALSALES II, LLC (Incorporated by reference to Exhibit 10.6 of the Registrant's Current Report on Form 8-K, filed October 25, 2007).
10.21	Settlement Agreement entered into as of October 24, 2013, by and among Patriot Coal Corporation, on behalf of itself and its affiliates, the Registrant, on behalf of itself and its affiliates, and the United Mine Workers of America, on behalf of itself and the UMWA Employees and UMWA Retirees (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed October 30, 2013).
10.22	Purchase and Sale Agreement, dated as of November 20, 2015, by and between Four Star Holdings, LLC and Western Megawatt Resources, LLC (Incorporated by reference to Exhibit 10.28 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2015).
10.23*	Employment Agreement entered into as of August 21, 2013, by and between Peabody Energy Corporation and Glenn L. Kellow (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 27, 2013).
10.24*	Restrictive Covenant Agreement entered into as of August 21, 2013, by and between Peabody Energy Corporation and Glenn L. Kellow (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on August 27, 2013).
10.25*	Letter dated January 27, 2015 to Glenn L. Kellow from the Chairman of the Compensation Committee of the Peabody Energy Corporation Board of Directors (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 28, 2015).
10.26*	Letter Agreement entered into as of January 27, 2015, by and between Peabody Energy Corporation and Glenn L. Kellow (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on January 28, 2015).
10.27*	Letter Agreement entered into as of April 20, 2015, by and between Peabody Energy Corporation and Glenn L. Kellow (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on April 21, 2015).
10.28*	Restated Employment Agreement entered into as of January 7, 2013 by and between the Registrant and Charles F. Meintjes (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed January 10, 2013).
10.29*	Restated Employment Agreement entered into as of December 20, 2012 by and between the Registrant and Kemal Williamson (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 26, 2012).
10.30*	Peabody Energy Corporation 2019 Executive Severance Plan. (Incorporated by reference to Exhibit 10.32 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2018).

10.31	Limited Waiver to Purchase and Sale Agreement by and between Four Star Holdings, LLC and Western Megawatt Resources, LLC dated March 30, 2016 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed March 31, 2016).
10.32	Fifth Amended and Restated Receivables Purchase Agreement, dated as of March 25, 2016, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed March 31, 2016).
10.33	First Amendment to the Fifth Amended and Restated Receivables Purchase Agreement, dated as of April 12, 2016, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as the Sole Purchaser, Committed Purchaser, LC Bank and LC Participant (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 13, 2016).
10.34	Second Amendment to the Fifth Amended and Restated Receivables Purchase Agreement, dated as of April 18, 2016, by and among Peabody Energy Corporation, P&L Receivables Company, LLC, the various Sub-Servicers listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as the Sole Purchaser, Committed Purchaser, LC Bank and LC Participant (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 22, 2016).
10.35	Superpriority Secured Debtor-In-Possession Credit Agreement, dated as of April 18, 2016, by and among Peabody Energy Corporation, the guarantors party thereto, the lenders party thereto and Citibank, N.A. as Administrative Agent and L/C Issuer (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed April 22, 2016).
10.36	Amendment No. 1 to Superpriority Secured Debtor-in-Possession Credit Agreement, dated as of May 9, 2016, by and among Peabody Energy Corporation, the guarantors party thereto, the lenders party thereto and Citibank, N.A. as Administrative Agent (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed May 24, 2016).
10.37	Amendment No. 2 to Superpriority Secured Debtor-in-Possession Credit Agreement, dated as of May 18, 2016, by and among Peabody Energy Corporation, the guarantors party thereto, the lenders party thereto, the issuing bank party thereto, and Citibank, N.A. as Administrative Agent (Incorporated by reference to Exhibit 10.2 of the Registrant's Current Report on Form 8-K, filed May 24, 2016).
10.38	Amendment No. 4 to the Superpriority Secured Debtor-In-Possession Credit Agreement, dated as of October 11, 2016, by and among Peabody Energy Corporation, Peabody Global Funding, LLC (f/k/a Global Center for Energy and Human Development, LLC) and certain Debtors parties thereto as guarantors, the lenders party thereto and Citibank, N.A., as administrative agent (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed on October 14, 2016).
10.39	Amendment No. 5 to Superpriority Secured Debtor-In-Possession Credit Agreement, by and among Peabody Energy Corporation, Peabody Global Funding, LLC (f/k/a Global Center for Energy and Human Development, LLC) and certain Debtors parties thereto as guarantors, the lenders party thereto and Citibank, N.A., as administrative agent (Incorporated by reference to the Registrant's Current Report on Form 8-K filed November 23, 2016).
10.40	Amendment No. 6 to Superpriority Secured Debtor-In-Possession Credit Agreement, by and among Peabody Energy Corporation, Peabody Global Funding, LLC and certain Debtors parties thereto as guarantors, the lenders party thereto and Citibank, N.A., as administrative agent (Incorporated by reference to the Registrant's Current Report on Form 8-K filed December 14, 2016).
10.41	Plan Support Agreement entered into as of December 22, 2016 by and among the Registrant and certain other parties thereto (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 23, 2016).
10.42	Private Placement Agreement entered into as of December 22, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed December 23, 2016).
10.43	Amendment to Private Placement Agreement entered into as of December 28, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 30, 2016).
10.44	Second Amendment to Private Placement Agreement entered into as of February 8, 2017 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.127 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016).
10.45	Backstop Commitment Agreement entered into as of December 23, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed December 23, 2016).
10.46	Amendment to Backstop Commitment Agreement entered into as of December 28, 2016 by and among the Registrant and certain of its creditors party thereto (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed December 30, 2016).

10.47	Share Sale and Purchase Agreement entered into as of November 3, 2016 by and among Peabody Australia Mining Pty Ltd, Peabody Energy Australia Pty Ltd, South32 Aluminium (Holdings) Pty Ltd, and South32 Treasury Limited (Incorporated by reference to Exhibit 10.124 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016).
10.48	Exit Facility Commitment Letter entered into as of January 11, 2017, by and among the Registrant, Goldman Sachs Bank USA, JPMorgan Chase Bank, N.A., Credit Suisse AG, Credit Suisse Securities (USA) LLC, Macquarie Capital Funding LLC and Macquarie Capital (USA) Inc. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 12, 2017).
10.49	Receivables Purchase Facility Commitment Letter entered into as of January 27, 2017, by and among the Registrant, P&L Receivables Company, LLC and PNC Bank, National Association (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 27, 2017).
10.50	Notice Letter and Term Sheet dated as of February 15, 2017, for Amendments to the Receivables Purchase Facility Commitment Letter entered into as of January 27, 2017, by and among the Registrant, P&L Receivables Company, LLC and PNC Bank, National Association (Incorporated by reference to Exhibit 10.128 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016).
10.51	Settlement Agreement dated as of March 13, 2017 by and among the Registrant, certain subsidiaries of the Registrant, and the United Mine Workers of America 1974 Pension Plan and Trust (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 17, 2017).
10.52	Sixth Amended and Restated Receivables Purchase Agreement, dated as of April 3, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various Sub-Servicers listed on the signature pages thereto, all Conduit Purchasers listed on the signature pages thereto, all Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.4 of the Registrant's Current Report on Form 8-K filed April 3, 2017).
10.53	First Amendment to the Sixth Amended and Restated Receivables Purchase Agreement, dated as of June 30, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, the various parties identified on the signature pages thereto as Sub-Servicers, Metropolitan Collieries Pty Ltd, and PNC Bank, National Association, as Administrator and as the sole Purchaser Agent, Committed Purchaser, LC Bank and LC Participant on the date thereof (Incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q, filed August 14, 2017).
10.54	Second Amendment to the Sixth Amended and Restated Receivables Purchase Agreement, dated as of December 13, 2017, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, Regions Bank, and PNC Bank, National Association, as Administrator and as the sole Purchaser Agent, Committed Purchaser, LC Bank and LC Participant on the date thereof (Incorporated by reference to Exhibit 10.57 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2017).
10.55	Fifth Amendment to the Sixth Amended and Restated Receivables Purchase Agreement, dated as of April 3, 2019, by and among P&L Receivables Company, LLC, Peabody Energy Corporation, all Committed Purchasers listed on the signature pages thereto, all Purchaser Agents listed on the signature pages thereto, all LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 4, 2019).
10.56	Credit Agreement dated as of April 3, 2017, among the Registrant, as Borrower, Goldman Sachs Bank USA, as Administrative Agent, and the other lenders party thereto (Incorporated by reference to Exhibit 10.3 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
10.57	Amendment No. 1 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of the Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of September 18, 2017 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed September 18, 2017).
10.58	Amendment No. 2 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of November 17, 2017 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed November 20, 2017).
10.59	Amendment No. 3 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of December 18, 2017 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed December 19, 2017).
10.60	Amendment No. 4 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of April 11, 2018 (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K, filed April 11, 2018).
10.61	Amendment No. 5 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto and Goldman Sachs Bank USA, as administrative agent, dated as of June 27, 2018 (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).

10.62	Amendment No. 6 to Credit Agreement, by and among Peabody Energy Corporation, the subsidiaries of Peabody Energy Corporation party thereto as reaffirming parties, the incremental revolving lenders party thereto, Goldman Sachs Bank USA, as existing administrative agent, and JPMorgan Chase Bank, N.A., as successor administrative agent, dated as of September 17, 2019 (Incorporated by reference to Exhibit 10.1 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).
10.63	Amendment No. 7 by and among Peabody Energy Corporation, the subsidiaries of the Peabody Energy Corporation party thereto as reaffirming parties, the lenders party thereto, and JPMorgan Chase Bank, N.A., as successor administrative agent, dated as of September 17, 2019 (Incorporated by reference to Exhibit 10.2 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).
10.64*	Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 4.6 of the Registrant's Registration Statement on Form S-8, filed April 3, 2017).
10.65	Registration Rights Agreement, dated as of April 3. 2017, among the Registrant and the stockholders party thereto (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed, April 3, 2017).
10.66	Form of Indemnification Agreement (Incorporated by reference to Exhibit 10.9 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.67*	Form of Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.7 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
10.68*	Form of Restrictive Covenant Agreement under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.8 of the Registrant's Current Report on Form 8-K, filed April 3, 2017).
10.69*	Form of Deferred Stock Unit Agreement under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.12 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.70*	Form of Performance Share Unit Agreement under the Peabody Energy Corporation 2017 Incentive Plan. (Incorporated by reference to Exhibit 10.68 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2017).
10.71	Form of Indemnification Agreement (Incorporated by reference to Exhibit 10.73 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2018).
10.72*	Form of Deferred Stock Unit Agreement under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.74 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 2018).
10.73*	Form of Restricted Stock Unit Agreement (ELT Level 2019 Special Award) under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.75 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).
10.74*	Form of Restricted Stock Unit Agreement (Director Level and Above 2019 Special Award) under the Peabody Energy Corporation 2017 Incentive Plan (Incorporated by reference to Exhibit 10.76 of the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).
21†	List of Subsidiaries.
23.1†	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm.
31.1†	Certification of periodic financial report by the Registrant's Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of periodic financial report by the Registrant's Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1†	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Executive Officer.
32.2†	Certification of periodic financial report pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by the Registrant's Chief Financial Officer.
95†	Mine Safety Disclosure required by Item 104 of Regulation S-K.
101.INS	Inline XBRL Instance Document - the instance document does not appear in the interactive data file because XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

*	These exhibits constitute all management contracts, compensatory plans and arrangements required to be filed as an exhibit to this form pursuant to Item 15(a)(3) and 15(b) of this report.
†	Filed herewith.

Exhibit 4.7

DESCRIPTION OF THE COMPANY'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a brief description of the common stock, par value $0.01 per share ("Common Stock"), of Peabody Energy Corporation (the "Company," "we," "us" or "our"), which is the only security of the Company registered pursuant to Section 12 of the Securities Exchange Act of 1934. The following summary is not complete and is qualified in its entirety by reference to the Company's Fourth Amended and Restated Certificate of Incorporation (the "Charter"), including the Certificate of Designation attached thereto, the Company's Amended and Restated Bylaws (the "Bylaws") and relevant sections of the Delaware General Corporation Law (the "DGCL").

General

We have the authority to issue a total of 450,000,000 shares of Common Stock, 100,000,000 shares of preferred stock, par value $0.01 per share ("Preferred Stock"), of which 50,000,000 were designated as Series A Convertible Preferred Stock ("Series A Preferred Stock"), and 50,000,000 shares of series common stock, par value $0.01 per share ("Series Common Stock").

The Board of Directors of the Company (the "Board") is granted authority to issue both Preferred Stock and Series Common Stock of one or more series and, in connection with the creation of any such series, to fix by the resolution or resolutions providing for the issue of shares, any designation, voting powers, preferences and relative, participating, optional, or other special rights of such series, and the qualifications, limitations or restrictions attaching thereto.

We may not issue non-voting equity securities; provided, however, that such restriction shall (a) not apply beyond what is required under Section 1123(a)(6) of the Bankruptcy Code, (b) only have such force and effect for so long as Section 1123 of the Bankruptcy Code is in effect and applicable to us, and (c) in all events may be amended or eliminated in accordance with applicable law.

Voting Rights

Subject to the voting rights granted to Preferred Stock or Series Common Stock that may be outstanding from time to time, each share of our Common Stock shall be entitled to one vote per share, in person or by proxy, on all matters submitted to a vote for our stockholders on which the holders of Common Stock are entitled to vote. Except as otherwise required in the Charter, Bylaws or by applicable law, the holders of voting stock shall vote together as one class on all matters submitted to a vote of stockholders generally. The Charter and Bylaws do not provide for cumulative voting in connection with the election of directors. Accordingly, holders of more than 50% of the shares voting will be able to elect all of the directors. However, in a contested election, a plurality of the votes shall be enough to elect a director. The holders of a majority of our voting stock issued and outstanding and entitled to vote at a meeting of stockholders, present in person or represented by proxy, constitute a quorum at any such meeting of stockholders for the transaction of business.

Dividend Rights

Subject to any dividend rights granted to Preferred Stock or Series Common Stock that may be outstanding from time to time, the holders of shares of Common Stock shall be entitled to receive such dividends and other distributions in cash, property or shares of stock as may be declared thereon by the Board from time to time out of the assets or funds legally available. Before payment of any dividend, there may be set aside out of any funds available for dividends such sum or sums as the directors, in their absolute discretion, think proper as a reserve or reserves to meet contingencies, or for equalizing dividends, or for repairing or maintaining any Company property, or for such other purpose as the directors shall think conducive to the interests of the Company, and the directors may modify or abolish any such reserve in the manner in which it was created.

No Preemptive Rights

No holder of our capital stock has any preemptive right to subscribe for any shares of our capital stock issued in the future.

Liquidation Rights

The holders of Common Stock shall be entitled to share ratably in the net assets remaining after payment pursuant to any liquidation rights granted to Preferred Stock or Series Common Stock that may be outstanding from time to time.

Preferred Stock

Series A Convertible Preferred Stock

In connection with the Company's emergence from its Chapter 11 cases in April 2017, the Company issued shares of new Series A Preferred Stock in a private placement. Under the terms of the Certificate of Designation relating to the Series A Preferred Stock, all outstanding shares of Series A Preferred Stock were mandatorily converted into shares of Common Stock on January 31, 2018. As of February 20, 2020, there are no shares of Series A Preferred Stock outstanding.

Other Preferred Stock

As of February 20, 2020, there are no shares of any series of Preferred Stock outstanding. The Charter provides that the Board may, by resolution, establish one or more series of Preferred Stock having the number of shares and relative voting rights, designations, dividend rates, liquidation and other rights, preferences and limitations as may be fixed by the Board without further stockholder approval. The holders of our Preferred Stock may be entitled to preferences over common stockholders with respect to dividends, liquidation, dissolution or our winding up in such amounts as are established by the resolutions of the Board approving the issuance of such shares.

The issuance of Preferred Stock may have the effect of delaying, deferring or preventing a change in control without further action by the holders and may adversely affect voting and other rights of holders of our securities. In addition, issuance of Preferred Stock, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could make it more difficult for a third party to acquire a majority of the outstanding shares of our voting stock.

Series Common Stock

As of February 20, 2020, there are no shares of Series Common Stock outstanding. The Charter provides that the Board may, by resolution, establish one or more series of Series Common Stock having the number of shares and relative voting rights, designations, dividend rates, liquidation and other rights, preferences and limitations as may be fixed by them without further stockholder approval. The holders of our Series Common Stock may be entitled to preferences over common stockholders and holders of Preferred Stock with respect to dividends, liquidation, dissolution or our winding up in such amounts as are established by the resolutions of our Board approving the issuance of such shares of Series Common Stock.

The issuance of Series Common Stock may have the effect of delaying, deferring or preventing a change in control without further action by the holders and may adversely affect voting and other rights of holders of our securities. In addition, issuance of Series Common Stock, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could make it more difficult for a third party to acquire a majority of the outstanding shares of our voting stock.

Provisions of Our Charter, Bylaws and Delaware Law That May Have an Anti-Takeover Effect

Preferred Stock and Series Common Stock

See above under “Preferred Stock” and “Series Common Stock.”

Special Meetings of Stockholders

The Charter and Bylaws provide that special meetings of the stockholders may be called by our Chairman of the Board, Chief Executive Officer, President or the Board. A special meeting of stockholders shall also be called by our secretary upon the written request of stockholders entitled to cast at least 40% of all votes entitled to be cast at the special meeting.

Advance Notice of Stockholder Meetings

Notice of any annual or special meeting of stockholders, stating the place (if any), date and hour of the meeting shall be given to each stockholder entitled to notice of such meeting not less than ten nor more than 60 days before the date of such meeting.

Advance Notice for Nominations or Stockholder Proposals at Meetings

The Bylaws also prescribe the procedure that a stockholder must follow to nominate directors or bring business before stockholder meetings.

Nominations of persons for election to the Board and the proposal of business at stockholder meetings may be made by (1) the Company, (2) the Chairman of the Board or (3) any stockholder entitled to vote and who makes the nomination or proposal pursuant to timely notice in proper written form to our Secretary in compliance with the procedures set forth in the Bylaws. For a stockholder to nominate a candidate for director or to bring other business before a meeting, we must receive notice not less than 90 days nor more than 120 days prior to the first anniversary of the preceding year’s annual meeting; provided, however, that in the event that the date of the annual meeting is advanced by more than 20 days, or delayed by more than 70 days from such anniversary date, notice by the stockholder must be so delivered not earlier than 120 days prior to such annual meeting and not later than the close of business on the later of the 90th day prior to such annual meeting or the 10th day following the day on which public announcement of the date of such meeting is made. Notice of a nomination for director must also include a description of various matters regarding the nominee and the shareholder giving notice, as set forth in the Bylaws.

In addition, the Bylaws permit a stockholder, or group of no more than 20 stockholders meeting specified eligibility requirements, to include director nominees in our proxy materials for annual meetings. In order to be eligible, stockholders must have owned 3% or more of the outstanding Common Stock continuously for at least three years. Requests to include stockholder-nominated candidates in our proxy materials must be delivered to us within the time periods applicable to stockholder notices of nominations as described in the preceding paragraph. The maximum number of stockholder nominated candidates is the greater of two directors or the largest whole number that does not exceed 20% of the number of directors in office as of last day on which a notice under these provisions is delivered. The Bylaws provide a process to determine which candidates under these provisions exceed the maximum permitted number. Each stockholder seeking to include a director nominee in our proxy materials pursuant to these provisions is required to provide certain information, as set forth in the Bylaws. A stockholder nominee must also meet certain eligibility requirements, as set forth in the Bylaws.

At a meeting of stockholders, only such business (other than the nomination of candidates for election as directors in accordance with the Bylaws) will be conducted or considered as is properly brought before the annual meeting or a special meeting as specified in the Bylaws.

Action by Written Consent

The Charter prohibits action by written consent by stockholders.

Directors

The Board shall consist of at least three members and no more than 15, and may be fixed from time to time by a resolution adopted by the Board or by the stockholders. As of February 20, 2020, the Board has 12 members. Directors need not be stockholders but are subject to a Company policy that requires that they hold shares of Common Stock having a value equal to a specified multiple of their annual retainer.

Each director to be elected by stockholders shall be elected by a majority vote of the stockholders, except that if the number of nominees exceeds the number of directors to be elected, the directors shall be elected by a plurality of votes. There is no cumulative voting in the election of directors. Directors may be removed, with or without cause, by a majority vote of our voting stock.

All directors will be in one class and serve for a term ending at the annual meeting following the annual meeting at which the director was elected. Our current class of directors will be subject to reelection at our 2020 annual meeting of stockholders

The Board is authorized to adopt, amend, alter or repeal the Bylaws by the affirmative vote of a majority of the directors present at any regular or special meeting, subject to the power of the voting stock to adopt, amend, alter or repeal the Bylaws made by the Board. Notwithstanding anything in the Charter or Bylaws to the contrary, a vote of holders of 75% or more of our voting stock is required to adopt, amend, alter or repeal any provision inconsistent with the foregoing or the manner in which action may be taken by voting stock.

Delaware Law

The Company is a Delaware corporation subject to Section 203 of the DGCL. Section 203 provides that, subject to certain exceptions specified in the law, a Delaware corporation shall not engage in certain “business combinations” with any “interested stockholder” for a three-year period following the time that the stockholder became an interested stockholder unless:

- prior to such time, the Board approved either the business combination or the transaction that resulted in the stockholder becoming an interested stockholder;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding certain shares; or

- at or subsequent to that time, the business combination is approved by the Board and authorized at an annual or special meeting of stockholders, and not by written consent, by the affirmative vote of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

Generally, a “business combination” includes a merger, asset or stock sale or other transaction resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an “interested stockholder” is a person who, together with that person’s affiliates and associates, owns, or within the previous three years did own, 15% or more of our outstanding voting stock.

Under certain circumstances, Section 203 makes it more difficult for a person who would be an “interested stockholder” to effect various business combinations for a three-year period. The provisions of Section 203 may encourage companies or other persons interested in acquiring us to negotiate in advance with the Board because the stockholder approval requirement would be avoided if the Board approves either the business combination or the transaction that results in the stockholder becoming an interested stockholder. These provisions also may have the effect of preventing changes in the Board and may make it more difficult to accomplish transactions that stockholders may otherwise deem to be in their best interests.

Exhibit 21

PEABODY ENERGY CORPORATION
LIST OF SUBSIDIARIES

Name of Subsidiary	Jurisdiction of Formation
9 East Shipping Limited	United Kingdom
American Land Development, LLC	Delaware
American Land Holdings of Colorado, LLC	Delaware
American Land Holdings of Illinois, LLC	Delaware
American Land Holdings of Indiana, LLC	Delaware
American Land Holdings of Kentucky, LLC	Delaware
Big Ridge, Inc.	Illinois
Big Sky Coal Company	Delaware
Bowen Basin Coal Joint Venture*	Australia
BTU International BV	Netherlands
BTU Western Resources, Inc.	Delaware
Burton Coal Pty Ltd.	Australia
Capricorn Joint Venture*	Australia
Carbones Peabody de Venezuela S.A.	Venezuela
Cardinal Gasification Center, LLC	Illinois
COALSALES II, LLC	Delaware
CO Employment Services, LLC	Delaware
Complejo Siderurgico Del Lago Cosila, SA	Venezuela
Conservancy Resources, LLC	Delaware
Coppabella and Moorvale Joint Venture*	Australia
Desarrollos Venshelf IV, CA	Venezuela
El Segundo Coal Company, LLC	Delaware
Excel Equities International Pty Ltd.	Australia
Excelven Pty Ltd.	British Virgin Islands
Hayden Gulch Terminal, LLC	Delaware
Helensburgh Coal Pty Ltd.	Australia
Hillside Recreational Lands, LLC	Delaware
Kayenta Mobile Home Park, Inc.	Delaware
Kentucky United Coal LLC	Indiana
Metropolitan Collieries Pty Ltd.	Australia
Middlemount Coal Pty Ltd	Australia
Middlemount Mine Management Pty Ltd	Australia
Millennium Coal Pty Ltd.	Australia
Moffat County Mining, LLC	Delaware
Moorvale West Joint Venture*	Australia
New Mexico Coal Resources, LLC	Delaware
Newhall Funding Company (MBT)	Massachusetts
NGS Acquisition Corp., LLC	Delaware
North Goonyella Coal Mines Pty Ltd.	Australia

North Wambo Pty Ltd.	Australia
Ocean Holdings, LLC	Delaware
P&L Receivables Company LLC	Delaware
PRB-CO JV, LLC	Delaware
PRB-CO JV Management Services, LLC	Delaware
PRB Employment Services, LLC	Delaware
Peabody (Bowen) Pty Ltd.	Australia
Peabody (Burton Coal) Pty Ltd.	Australia
Peabody (Kogan Creek) Pty Ltd.	Australia
Peabody (Wilkie Creek) Pty Ltd.	Australia
Peabody America, LLC	Delaware
Peabody Arclar Mining, LLC	Indiana
Peabody Asset Holdings, LLC	Delaware
Peabody Australia Holdco Pty Ltd.	Australia
Peabody Australia Mining Pty Ltd.	Australia
Peabody BB Interests Pty Ltd	Australia
Peabody Bear Run Mining, LLC	Delaware
Peabody Bear Run Services, LLC	Delaware
Peabody Bistrotel Pty Ltd	Australia
Peabody Caballo Mining, LLC	Delaware
Peabody Capricorn Pty Ltd	Australia
Peabody Cardinal Gasification, LLC	Delaware
Peabody China, LLC	Delaware
Peabody CHPP Pty Ltd	Australia
Peabody Coal Venezuela Ltd.	Bermuda
Peabody COALSALES, LLC	Delaware
Peabody COALSALES Pacific Pty Ltd	Australia
Peabody COALTRADE Asia Private Ltd.	Singapore
Peabody COALTRADE GmbH	Germany
Peabody COALTRADE India Private Ltd	India
Peabody COALTRADE International Limited	United Kingdom
Peabody COALTRADE, LLC	Delaware
Peabody Colorado Operations, LLC	Delaware
Peabody Colorado Services, LLC	Delaware
Peabody Coppabella Pty Ltd	Australia
Peabody Coulterville Mining, LLC	Delaware
Peabody Custom Mining Ltd	Australia
Peabody Development Company, LLC	Delaware
Peabody Electricity, LLC	Delaware
Peabody Employment Services, LLC	Delaware
Peabody Energy Australia Coal Pty Ltd.	Australia
Peabody Energy Australia PCI (C&M Equipment) Pty Ltd	Australia
Peabody Energy Australia PCI (C&M Management) Pty Ltd	Australia
Peabody Energy Australia PCI Equipment Pty Ltd	Australia
Peabody Energy Australia PCI Financing Pty Ltd	Australia
Peabody Energy Australia PCI Mine Management Pty Ltd	Australia

Peabody Energy Australia PCI Pty Ltd	Australia
Peabody Energy Australia PCI Rush Pty Ltd	Australia
Peabody Energy Australia Pty Ltd	Australia
Peabody Energy Finance Pty Ltd.	Australia
Peabody Energy (Gibraltar) Limited	Gibraltar
Peabody Gateway North Mining, LLC	Delaware
Peabody Gateway Services, LLC	Delaware
Peabody Global Funding, LLC	Delaware
Peabody Global Holdings, LLC	Delaware
Peabody Global Services Pte Ltd.	Singapore
Peabody Holding Company, LLC	Delaware
Peabody Holland BV	Netherlands
Peabody IC Funding Corp.	Delaware
Peabody Illinois Services, LLC	Delaware
Peabody Indiana Services, LLC	Delaware
Peabody International (Gibraltar) Ltd.	Gibraltar
Peabody International Holdings, LLC	Delaware
Peabody International Investments, Inc.	Delaware
Peabody International Services, Inc.	Delaware
Peabody Investment & Development Business Services Beijing Co. Ltd.	China
Peabody Investments (Gibraltar) Limited	Gibraltar
Peabody Investments Corp.	Delaware
Peabody MCC (Gibraltar) Limited	Gibraltar
Peabody Midwest Management Services, LLC	Delaware
Peabody Midwest Mining, LLC	Indiana
Peabody Midwest Operations, LLC	Delaware
Peabody Midwest Services, LLC	Delaware
Peabody Mongolia, LLC	Delaware
Peabody Monto Coal Pty Ltd	Australia
Peabody Moorvale West Pty Ltd.	Australia
Peabody Moorvale Pty Ltd	Australia
Peabody Natural Gas, LLC	Delaware
Peabody Natural Resources Company	Delaware
Peabody New Mexico Services, LLC	Delaware
Peabody Olive Downs Pty Ltd.	Australia
Peabody Operations Holding, LLC	Delaware
Peabody Pastoral Holdings Pty Ltd	Australia
Peabody Powder River Mining, LLC	Delaware
Peabody Powder River Operations, LLC	Delaware
Peabody Powder River Services, LLC	Delaware
Peabody Rocky Mountain Management Services, LLC	Delaware
Peabody Rocky Mountain Services, LLC	Delaware
Peabody Sage Creek Mining, LLC	Delaware
Peabody School Creek Mining, LLC	Delaware
Peabody Services Holding, LLC	Delaware
Peabody Southeast Mining, LLC	Delaware

Peabody Twentymile Mining, LLC	Delaware
Peabody Venezuela Coal Corp.	Delaware
Peabody Venture Fund, LLC	Delaware
Peabody-Waterside Development, L.L.C.	Delaware
Peabody West Burton Pty Ltd	Australia
Peabody Western Coal Company	Delaware
Peabody West Rolleston Pty Ltd.	Australia
Peabody West Walker Pty Ltd.	Australia
Peabody Wild Boar Mining, LLC	Delaware
Peabody Wild Boar Services, LLC	Delaware
Peabody Williams Fork Mining, LLC	Delaware
Peabody Wyoming Services, LLC	Delaware
PEC Equipment Company, LLC	Delaware
PT Peabody Coaltrade Indonesia	Indonesia
PT Peabody Mining Services	Indonesia
Ribfield Pty Ltd	Australia
SAGE CREEK HOLDINGS, LLC	Delaware
Sage Creek Land & Reserves, LLC	Delaware
Seneca Coal Company, LLC	Delaware
Seneca Property, LLC	Delaware
Shoshone Coal Corporation	Delaware
Sterling Centennial Missouri Insurance Corporation	Missouri
Transportes Coal Sea de Venezuela, CA	Venezuela
Twentymile Coal LLC	Delaware
United Minerals Company LLC	Indiana
Wambo Coal Pty Ltd.	Australia
Wambo Coal Terminal Pty Ltd	Australia
Wambo Open Cut Pty Ltd.	Australia
West Rolleson Joint Venture*	Australia
West Walker Joint Venture*	Australia
West/North Burton Joint Venture*	Australia
Wilpinjong Coal Pty Ltd.	Australia

*Unincorporated joint venture.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-217107) pertaining to the Peabody Energy Corporation 2017 Incentive Plan of our reports dated February 21, 2020, with respect to the consolidated financial statements and schedule of Peabody Energy Corporation and the effectiveness of internal control over financial reporting of Peabody Energy Corporation included in this Annual Report (Form 10-K) of Peabody Energy Corporation for the year ended December 31, 2019.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 21, 2020

Exhibit 31.1

CERTIFICATION

I, Glenn L. Kellow, certify that:

1. I have reviewed this Annual Report on Form 10-K of Peabody Energy Corporation (“the registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2020

/s/ Glenn L. Kellow

Glenn L. Kellow
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Mark A. Spurbeck, certify that:

1. I have reviewed this Annual Report on Form 10-K of Peabody Energy Corporation (“the registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2020

/s/ Mark A. Spurbeck

Mark A. Spurbeck
Interim Chief Financial Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)**

I, Glenn L. Kellow, President and Chief Executive Officer of Peabody Energy Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the annual period ended December 31, 2019 (the “Annual Report”) which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of Peabody Energy Corporation.

Dated: February 21, 2020

/s/ Glenn L. Kellow
Glenn L. Kellow
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

I, Mark A. Spurbeck, Interim Chief Financial Officer of Peabody Energy Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the annual period ended December 31, 2019 (the “Annual Report”) which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of Peabody Energy Corporation.

Dated: February 21, 2020

/s/ Mark A. Spurbeck
Mark A. Spurbeck
Interim Chief Financial Officer

Mine Safety Disclosures

The following disclosures are provided pursuant to Securities and Exchange Commission (SEC) regulations, which require certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate coal mines regulated under the Federal Mine Safety and Health Act of 1977 (the Mine Act). The disclosures reflect United States (U.S.) mining operations only, as these requirements do not apply to our mines operated outside the U.S.

Mine Safety Information. Whenever the Mine Safety and Health Administration (MSHA) believes that a violation of the Mine Act, any health or safety standard, or any regulation has occurred, it may issue a violation which describes the associated condition or practice and designates a timeframe within which the operator must abate the violation. In some situations, such as when MSHA believes that conditions pose a hazard to miners, MSHA may issue an order removing miners from the area of the mine affected by the condition until hazards are corrected. Whenever MSHA issues a citation or order, it generally proposes a civil penalty, or fine, as a result of the violation that the operator is ordered to pay. Citations and orders can be contested and appealed and, as part of that process, are often reduced in severity and amount, and are sometimes vacated. The number of citations, orders and proposed assessments vary depending on the size and type (underground or surface) of the company and mine. Since MSHA is a branch of the U.S. Department of Labor, its jurisdiction applies only to our U.S. mines. As such, the mine safety disclosures that follow contain no information for our Australian mines.

The table that follows reflects citations and orders issued to us by MSHA during the year ended December 31, 2019, as reflected in our systems. The table includes only those mines that were issued orders or citations during the period presented and, commensurate with SEC regulations, does not reflect orders or citations issued to independent contractors working at our mines. Due to timing and other factors, our data may not agree with the mine data retrieval system maintained by MSHA. The proposed assessments for the year ended December 31, 2019 were taken from the MSHA system as of February 20, 2020.

Additional information about MSHA references used in the table is as follows:

- *Section 104 S&S Violations*: The total number of violations received from MSHA under section 104(a) of the Mine Act that could significantly and substantially contribute to a serious injury if left unabated.
- *Section 104(b)Orders*: The total number of orders issued by MSHA under section 104(b) of the Mine Act, which represents a failure to abate a citation under section 104(a) within the period of time prescribed by MSHA. This results in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.
- *Section 104(d) Citations and Orders*: The total number of citations and orders issued by MSHA under section 104(d) of the Mine Act for unwarrantable failure to comply with mandatory health or safety standards.
- *Section 104(e) Notices*: The total number of notices issued by MSHA under section 104(e) of the Mine Act for a pattern of violations that could contribute to mine health or safety hazards.
- *Section 110(b)(2)Violations*: The total number of flagrant violations issued by MSHA under section 110(b)(2) of the Mine Act.
- *Section 107(a) Orders*: The total number of orders issued by MSHA under section 107(a) of the Mine Act for situations in which MSHA determined an imminent danger existed.
- *Proposed MSHA Assessments*: The total dollar value of proposed assessments from MSHA.
- *Fatalities*: The total number of mining-related fatalities.

Year Ended December 31, 2019

Mine [1]	Section 104 S&S Violations	Section 104(b) Orders	Section 104(d) Citations and Orders	Section 104(e) Pattern of Violations	Section 110(b)(2) Violations	Section 107(a) Orders	($) Proposed MSHA Assessments	Fatalities
							(In thousands)	
Seaborne Metallurgical Mining								
Shoal Creek Mine	113	1	7	—	—	—	289.6	—
Powder River Basin Mining								
Caballo	—	—	—	—	—	—	3.9	—
North Antelope Rochelle	4	—	—	—	—	—	16.8	—
Rawhide	4	—	—	—	—	—	8.1	—
Midwestern U.S. Mining								
Arclar Preparation Plant	—	—	—	—	—	—	0.1	—
Bear Run	8	—	—	—	—	—	27.5	—
Francisco Preparation Plant (Francisco Mine)	1	—	—	—	—	—	0.9	—
Francisco Underground	41	—	—	—	—	—	109.6	—
Gateway North	24	—	—	—	—	—	107.5	—
Gateway Preparation Plant	—	—	—	—	—	—	0.4	—
Somerville Central	3	—	—	—	—	—	3.0	—
Wild Boar	1	—	—	—	—	—	1.7	—
Wildcat Hills Cottage Grove Pit	3	—	—	—	—	—	4.8	—
Wildcat Hills Underground	41	—	—	—	—	—	94.4	—
Western U.S. Mining								
El Segundo	6	—	—	—	—	—	7.2	—
Kayenta	1	—	—	—	—	—	2.2	—
Twentymile (Foidel Creek Mine)	14	—	—	—	—	—	171.3	—

[1] The definition of "mine" under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting coal, such as land, structures, facilities, equipment, machines, tools and coal preparation facilities. Also, there are instances where the mine name per the MSHA system differs from the mine name utilized by us. Where applicable, we have parenthetically listed the name of the mine per the MSHA system. Also, all U.S. mines are listed alphabetically within each of our mining segments.

Pending Legal Actions. The Federal Mine Safety and Health Review Commission (the Commission) is an independent adjudicative agency that provides administrative trial and appellate review of legal disputes arising under the Mine Act. These cases may involve, among other questions, challenges by operators to citations, orders and penalties they have received from MSHA, or complaints of discrimination by miners under section 105 of the Mine Act. The following is a brief description of the types of legal actions that may be brought before the Commission.

- *Contests of Citations and Orders*: A contest proceeding may be filed with the Commission by operators, miners or miners' representatives to challenge the issuance of a citation or order issued by MSHA, including citations related to disputed provisions of operators' emergency response plans.
- *Contests of Proposed Penalties (Petitions for Assessment of Penalties)*: A contest of a proposed penalty is an administrative proceeding before the Commission challenging a civil penalty that MSHA has proposed for the violation. Such proceedings may also involve appeals of judges' decisions or orders to the Commission on proposed penalties, including petitions for discretionary review and review by the Commission on its own motion.
- *Complaints for Compensation*: A complaint for compensation may be filed with the Commission by miners entitled to compensation when a mine is closed by certain withdrawal orders issued by MSHA. The purpose of the proceeding is to determine the amount of compensation, if any, due miners idled by the orders.
- *Complaints of Discharge, Discrimination or Interference*: A discrimination proceeding is a case that involves a miner's allegation that he or she has suffered a wrong by the operator because he or she engaged in some type of activity protected under the Mine Act, such as making a safety complaint. This category includes temporary reinstatement proceedings, which involve cases in which a miner has filed a complaint with MSHA stating he or she has suffered discrimination and the miner has lost his or her position.
- *Applications for Temporary Relief:* An application for temporary relief from any modification or termination of any order or from any order issued under certain subparts of section 104 of the Mine Act may be filed with the Commission at any time before such order becomes final.

The table that follows presents information by mine regarding pending legal actions before the Commission at December 31, 2019. Each legal action is assigned a docket number by the Commission and may have as its subject matter one or more citations, orders, penalties or complaints.

	Pending Legal Actions							
Mine [(1)]	Number of Pending Legal Actions as of December 31, 2019	Pre-Penalty Contests of Citations/Orders	Contests of Penalty Assessment [(2)]	Complaints for Compensation	Complaints of Discharge, Discrimination or Interference	Applications for Temporary Relief	Legal Actions Initiated During the Year Ended December 31, 2019	Legal Actions Resolved During the Year Ended December 31, 2019
Seaborne Metallurgical Mining								
Shoal Creek Mine	8	—	8	—	—	—	10	2
Powder River Basin Mining								
North Antelope Rochelle	—	—	—	—	—	—	—	3
Midwestern U.S. Mining								
Bear Run	1	—	1	—	—	—	2	1
Francisco Underground	7	—	7	—	—	—	4	10
Somerville Central	—	—	—	—	—	—	—	2
Wildcat Hills Underground	1	—	1	—	—	—	3	5
Western U.S. Mining								
El Segundo	—	—	—	—	—	—	1	1
Twentymile (Foidel Creek)	3	—	3	—	—	—	6	11

(1) The definition of "mine" under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting coal, such as land, structures, facilities, equipment, machines, tools and coal preparation facilities. Also, there are instances where the mine name per the MSHA system differs from the mine name utilized by us. Where applicable, we have parenthetically listed the name of the mine per the MSHA system. Also, all U.S. mines are listed alphabetically within each of our mining segments.

(2) Contests included a total of 1 appeal of judge's decisions or orders to the Commission as of December 31, 2019.