ARCH COAL INC
Form 10-K
February 14, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549
Form 10-K
(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
or
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 1-13105

Arch Coal, Inc.
(Exact name of registrant as specified in its charter)

Delaware	43-0921172
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
One CityPlace Drive, Ste. 300, St. Louis, Missouri	63141
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: (314) 994-2700

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value	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 x 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 x

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 x 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 x No¨

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

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Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 x 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 Act). Yes ¨ No x

The aggregate market value of the voting stock held by non-affiliates of the registrant (excluding outstanding shares beneficially owned by directors, officers, other affiliates and treasury shares) as of June 30, 2018 was approximately $1.5 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 x No ¨

At February 1, 2019 there were 17,688,875 shares of the registrant’s common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s definitive proxy statement to be filed with the Securities and Exchange Commission in connection with the 2019 annual stockholders’ meeting are incorporated by reference into Part III of this Form 10-K.

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If you are not familiar with any of the mining terms used in this report, we have provided explanations of many of them under the caption "Glossary of Selected Mining Terms" on page 32 of this report. Unless the context otherwise requires, all references in this report to "Arch," "we," "us," or "our" are to Arch Coal, Inc. and its subsidiaries.

CAUTIONARY STATEMENTS REGARDING FORWARD LOOKING INFORMATION

This report contains forward looking statements, within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, such as our expected future business and financial performance, and are intended to come within the safe harbor protections provided by those sections. The words "anticipates," "believes," "could," "estimates," "expects," "intends," "may," "plans," "predicts," "projects," "seeks, other comparable words and phrases identify forward looking statements, which speak only as of the date of this report. Forward looking statements by their nature address matters that are, to different degrees, uncertain. Actual results may vary significantly from those anticipated due to many factors, including:

- our emergence from Chapter 11 bankruptcy protection;
- market demand for coal, or a specific type of coal such as metallurgical, and electricity;
- geologic conditions, weather and other inherent risks of coal mining that are beyond our control;
- competition, both within our industry and with producers of competing energy sources, including the effects from any current or future legislation or regulations designed to support, promote or mandate renewable energy sources;
- excess production and production capacity;
- our ability to acquire or develop coal reserves in an economically feasible manner;
- inaccuracies in our estimates of our coal reserves;
- availability and price of mining and other industrial supplies;
- availability of skilled employees and other workforce factors;
- our ability to collect payments from our customers;
- defects in title or the loss of a leasehold interest;
- railroad, barge, truck, ocean vessel and other transportation performance and costs;
- our ability to successfully integrate the operations that we acquire;
- our ability to secure new coal supply arrangements or to renew existing coal supply arrangements;
- our relationships with, and other conditions affecting our customers;
- the loss of, or significant reduction in, purchases by our largest customers;
- our ability to service our outstanding indebtedness;
- our ability to comply with the restrictions imposed by our Term Loan Debt Facility, Securitization Facility or Inventory Facility (each as defined below), other financing arrangements or any subsequent financing or credit facilities;
- the availability and cost of surety bonds;
- our ability to manage the market and other risks associated with certain trading and other asset optimization strategies;

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- risks due to our international operations;
- cyber-attacks or other security breaches that disrupt our operations, or that result in the unauthorized release of proprietary or confidential information;
- the loss of key personnel or the failure to attract additional qualified personnel;
- our ability to pay dividends or repurchase shares of our common stock in accordance with our announced intent or at all;
- the effects of foreign and domestic trade policies, actions or disputes on the level of trade among the countries and regions in which we operate, the competitiveness of our exports, or our ability to export;
- terrorist attacks, military action or war;
- our ability to obtain and renew various permits, including permits authorizing the disposition of certain mining waste;
- existing and future legislation and regulations affecting both our coal mining operations and our customers' coal usage, governmental policies and taxes, including those aimed at reducing emissions of elements such as mercury, sulfur dioxides, nitrogen oxides, particulate matter or greenhouse gases;
- the accuracy of our estimates of reclamation and other mine closure obligations;
- the existence of hazardous substances or other environmental contamination on property owned or used by us;
- existing and future litigation based on the alleged effects of climate change; and
- other factors, including those discussed in "Legal Proceedings", set forth in Item 3 of this report and "Risk Factors," set forth in Item 1A of this report.

All forward looking statements in this report, as well as all other written and oral forward looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. These factors are not necessarily all of the important factors that could affect us. These risks and uncertainties, as well as other risks of which we are not aware or which we currently do not believe to be material, may cause our actual future results to be materially different than those expressed in our forward looking statements. These forward looking statements speak only as of the date on which such statements were made, and we do not undertake to update our forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by the federal securities laws.

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PART I

ITEM 1. BUSINESS

Introduction

We are one of the world's largest coal producers. For the year ended December 31, 2018, we sold approximately 97 million tons of coal, including approximately 1.1 million tons of coal we purchased from third parties. We sell substantially all of our coal to power plants, steel mills and industrial facilities. At December 31, 2018, we operated 9 active mines located in each of the major coal-producing regions of the United States. The locations of our mines and access to export facilities enable us to ship coal worldwide. We incorporate by reference the information about the geographical breakdown of our coal sales for the respective periods covered within this Form 10-K contained in Note 23 to the Consolidated Financial Statements.

Our History

We were organized in Delaware in 1969 as Arch Mineral Corporation. In July 1997, we merged with Ashland Coal, Inc., a subsidiary of Ashland Inc. that was formed in 1975. As a result of the merger, we became one of the largest producers of low sulfur coal in the eastern United States.

In June 1998, we expanded into the western United States when we acquired the coal assets of Atlantic Richfield Company. This acquisition included the Black Thunder and Coal Creek mines in the Powder River Basin of Wyoming, the West Elk mine in Colorado and a 65% interest in Canyon Fuel Company, which operated three mines in Utah. In October 1998, we acquired a leasehold interest in the Thundercloud reserve, a 412 million ton federal reserve tract adjacent to the Black Thunder mine.

In July 2004, we acquired the remaining 35% interest in Canyon Fuel Company. In August 2004, we acquired Triton Coal Company's North Rochelle mine adjacent to our Black Thunder operation. In September 2004, we acquired a leasehold interest in the Little Thunder reserve, a 719 million ton federal reserve tract adjacent to the Black Thunder mine.

In December 2005, we sold the stock of Hobet Mining, Inc., Apogee Coal Company and Catenary Coal Company and their four associated mining complexes (Hobet 21, Arch of West Virginia, Samples and Campbells Creek) and approximately 455 million tons of coal reserves in Central Appalachia to Magnum Coal Company, which was subsequently acquired by Patriot Coal Corporation.

In October 2009, we acquired Rio Tinto's Jacobs Ranch mine complex in the Powder River Basin of Wyoming, which included 345 million tons of low cost, low sulfur coal reserves, and integrated it into the Black Thunder mine.

In June 2011, we acquired International Coal Group, Inc., which owned and operated mines primarily in the Appalachian Region of the United States.

In August 2013, we sold the equity interests of Canyon Fuel Company, LLC ("Canyon Fuel"), which owned and operated our Utah operations.

Restructuring Under Chapter 11 of the United States Bankruptcy Code

On January 11, 2016 (the "Petition Date"), Arch and substantially all of its wholly owned domestic subsidiaries (the "Filing Subsidiaries" and, together with Arch, the "Debtors") filed voluntary petitions for reorganization (collectively, the "Bankruptcy Petitions") under Chapter 11 of Title 11 of the U.S. Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Eastern District of Missouri (the "Court"). The Debtor's Chapter 11 Cases (collectively, the "Chapter 11 Cases") were jointly administered under the caption In re Arch Coal, Inc., et al. Case No. 16-40120 (lead case). During the bankruptcy proceedings, each Debtor operated its business as a "debtor in possession" under the jurisdiction of the Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Court.

On September 13, 2016, the Bankruptcy Court entered an order, Docket No. 1324, confirming the Debtors' Fourth Amended Joint Plan of Reorganization under Chapter 11 of the Bankruptcy Code dated as of September 11, 2016 (the "Plan"), which order was amended on September 15, 2016, Docket No. 1334.

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On October 5, 2016, Arch Coal emerged from Chapter 11 and the Plan became effective on such date (the “Effective Date”).

On the Plan Effective Date, we applied fresh start accounting which required us to allocate our reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. In addition to fresh start accounting, our consolidated financial statements reflect all impacts of the transactions contemplated by the Plan. Under the provisions of fresh start accounting, a new entity has been created for financial reporting purposes. We selected an accounting convenience date of October 1, 2016 for purposes of applying fresh start accounting as the activity between the convenience date and the Effective Date does 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 October 2, 2016; references to “Predecessor” in the financial statements and accompanying footnotes are in reference to reporting dates through October 1, 2016 which includes the impact of the Plan provisions and the application of fresh start accounting. As such, our 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 accounting and prior to the accounting for the effects of the Plan.

For additional information, see Note 1, “Basis of Presentation” and Note 3, “Emergence from Bankruptcy and Fresh Start Accounting” to our Consolidated Financial Statements included within this Form 10-K.

Coal Characteristics

End users generally characterize coal as thermal coal or metallurgical coal. Heat value, sulfur, ash, moisture content, and volatility, in the case of metallurgical coal, are important variables in the marketing and transportation of coal. These characteristics help producers determine the best end use of a particular type of coal. The following is a description of these general coal characteristics:

Heat Value. In general, the carbon content of coal supplies most of its heating value, but other factors also influence the amount of energy it contains per unit of weight. The heat value of coal is commonly measured in Btus. Coal is generally classified into four categories, lignite, subbituminous, bituminous and anthracite, reflecting the progressive response of individual deposits of coal to increasing heat and pressure. Anthracite is coal with the highest carbon content and, therefore, the highest heat value, nearing 15,000 Btus per pound. Bituminous coal, used primarily to generate electricity and to make coke for the steel industry, has a heat value ranging between 10,500 and 15,500 Btus per pound. Subbituminous coal ranges from 8,300 to 13,000 Btus per pound and is generally used for electric power generation. Lignite coal is a geologically young coal which has the lowest carbon content and a heat value ranging between 4,000 and 8,300 Btus per pound.

Sulfur Content. Federal and state environmental regulations, including regulations that limit the amount of sulfur dioxide that may be emitted as a result of combustion, have affected and may continue to affect the demand for certain types of coal. The sulfur content of coal can vary from seam to seam and within a single seam. The chemical composition and concentration of sulfur in coal affects the amount of sulfur dioxide produced in combustion. Coal fueled power plants can comply with sulfur dioxide emission regulations by burning coal with low sulfur content, blending coals with various sulfur contents, purchasing emission allowances on the open market and/or using sulfur dioxide emission reduction technology.

Ash. Ash is the inorganic residue remaining after the combustion of coal. As with sulfur, ash content varies from seam to seam. Ash content is an important characteristic of coal because it impacts boiler performance and electric generating plants must handle and dispose of ash following combustion. The composition of the ash, including the proportion of sodium oxide and fusion temperature, is also an important characteristic of coal, as it helps to determine the suitability of the coal to end users. The absence of ash is also important to the process by which metallurgical coal is transformed into coke for use in steel production.

Moisture. Moisture content of coal varies by the type of coal, the region where it is mined and the location of the coal within a seam. In general, high moisture content decreases the heat value and increases the weight of the coal, thereby making it more expensive to transport. Moisture content in coal, on an as sold basis, can range from approximately 2%

to over 30% of the coal’s weight.

Other. Users of metallurgical coal measure certain other characteristics, including fluidity, swelling capacity and volatility to assess the strength of coke produced from a given coal or the amount of coke that certain types of coal will yield. These characteristics may be important elements in determining the value of the metallurgical coal we produce and market.

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The Coal Industry

Background. Coal is mined globally using various methods of surface and underground recovery. Coal is used primarily for the generation of electric power and steel but is also used for chemical, food and cement processing. Coal is traded globally and can be transported to demand centers by ship, rail, barge, truck or conveyor belt. Total world coal production exceeded 7.5 billion metric tons in 2018 according to the International Energy Agency (IEA). China is the largest producer of coal in the world, producing over 3.5 billion metric tons in 2018 according to the Chinese Bureau of Statistics. The United States and India follow China with total coal production of over 650 million metric tons each in 2018 based on preliminary data.

The primary nations that are supplying coal to the global power and steel markets are Australia and Indonesia, as well as Russia, the United States, Canada, Colombia and South Africa.

We produce coal used for electric power generation (thermal) and coal used in the production of steel (metallurgical). All of our thermal coal production occurs in the United States at mines located in Wyoming, Colorado, Illinois, and West Virginia. Subsequent to the sale of our Lone Mountain operation in the third quarter of 2017, our metallurgical coal is produced at operations in West Virginia. Heat value and sulfur content are the most important variables in the economic marketing and transportation of thermal coal. Carbon content, the composition of the non-carbon volatiles and other chemical constituents are critical characteristics for metallurgical coal.

Much of our coal is sold at the mine where title and risk of loss transfer to the customer as coal is loaded into the railcar or truck. Customers are responsible for transportation - typically using third party carriers. There are some agreements where we retain responsibility for the coal during delivery to the customer site or intermediate terminal. Our international coal usually changes title and risk of loss as coal is loaded on an ocean vessel. We, or our agent, contracts for transportation services to the ocean loading port. On rare occasion, we might retain title to the coal to the ocean delivery port.

We seek to establish long-term relationships with customers through exemplary customer service while operating safe and environmentally responsible mines. In 2018, we shipped to 32 states and 19 countries. During the year, we supplied coal to 97 domestic and 37 foreign customers. In 2018, approximately 92% of our coal sales volume was sold as a thermal product with the remaining 8% as metallurgical. However, due to the significantly higher selling price of our metallurgical coal, our metallurgical segment contributed 42% of our sales revenue in 2018.

Coal was used to produce approximately 27% of the electric power generated in the U.S. in 2018 based on preliminary data from the Energy Information Administration (EIA.) The coal we produced fueled approximately 4% of the electricity produced in the U.S. in 2018. We also exported 6% of our thermal coal production to customers outside the U.S. in 2018.

We rank among the largest metallurgical coal producers in the U.S. Based on internal estimates, we produced around 8% of total U.S. metallurgical coal in 2018. Our metallurgical coal was sold to 7 domestic customers and shipped to 18 international destinations in 2018.

We operate in a very competitive environment. We compete with domestic and international coal producers, traders or brokers as well as producers of other energy sources including natural gas, renewables and nuclear, as well as other non-coal based forms of steel production. We compete using price, coal quality, transportation, optionality, customer administration, reputation and reliability.

Coal demand and coal prices are tied to coal consumption patterns which are influenced by many uncontrollable factors. For power generation, the price of coal is affected by the relative supply and demand of competitive coal, transportation, availability and price of other non-coal forms of power production (particularly, natural gas), regulatory limits on using coal, taxes, the weather and economic conditions. For metallurgical coal, the price of coal is affected by the supply, demand and price of competitive coal, transportation, the price of steel, demand for steel, as well as regulations, taxes and economic conditions.

We have an experienced and knowledgeable sales and marketing group. This group is dedicated to meeting customer needs, coordinating transportation, providing accounting services and managing risk.

U.S. Coal Production. The United States is among the top three largest coal producers in the world, exceeded only by China and roughly equivalent to India based on preliminary data. According to the EIA, there are over 250 billion short tons of

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recoverable coal in the United States. The U.S. Department of Energy estimates that current domestic recoverable coal reserves could supply enough electricity to satisfy domestic demand for over 300 years.

Coal is mined from coal basins throughout the United States, with the major production centers located in the western United States, the Appalachian region and the Interior. According to the EIA and Mine Safety and Health Administration (MSHA), U.S. coal production decreased by an estimated 20 million tons in 2018, to 754 million tons.

The EIA subdivides United States coal production into three major areas: Western, Appalachia and Interior.

The Western area includes the Powder River Basin and the Western Bituminous region. According to the EIA, coal produced in the western United States decreased from an estimated 431 million short tons in 2017 to 416 million short tons in 2018. The Powder River Basin is located in northeastern Wyoming and southeastern Montana and is the largest producing region in the United States. Coal from this region is sub-bituminous coal with low sulfur content ranging from 0.2% to 0.9% and heating values ranging from 8,300 to 9,500 Btu. The price of Powder River Basin coal is generally less than that of coal produced in other regions because Powder River Basin coal has a lower heat content, however it is produced from thick seams using surface recovery methods thus, has a lower cost of production. The Western Bituminous region includes Colorado, Utah and southern Wyoming. Coal from this region typically has low sulfur content ranging from 0.4% to 0.8% and heating values ranging from 10,000 to 12,200 Btu. Western bituminous coal has certain quality characteristics, especially its higher heat content and low sulfur, that make this a desirable coal for domestic and international power producers.

The Appalachia region is divided into north, central and southern regions. According to the EIA, coal produced in the Appalachian region increased from 198 million short tons in 2017 to 201 million short tons in 2018. Appalachian coal is located near the prolific eastern shale-gas producing regions. Central Appalachian thermal coal is disadvantaged for power generation because of the depletion of economically attractive reserves, increasing costs of production and permitting issues. However, virtually all U.S. metallurgical coal is produced in Appalachia and the relative scarcity and high-quality of this coal allows for a pricing premium over thermal coal. Appalachia, while still a major producer of thermal coal, is undergoing a shift towards heavier reliance on metallurgical coal production for both domestic and international use. This is especially the case in Central Appalachia.

Northern Appalachia includes Pennsylvania, Northern West Virginia, Ohio and Maryland. Coal from this region generally has a high heat value ranging from 10,300 to 13,500 Btu and a sulfur content ranging from 0.8% to 4.0%. Central Appalachia includes Southern West Virginia, Virginia, Kentucky and Northern Tennessee. Coal mined from this region generally has a high heat value ranging from 11,400 to 13,200 Btu and low sulfur content ranging from 0.2% to 2.0%. Southern Appalachia primarily covers Alabama and generally has a heat content ranging from 11,300 to 12,300 Btu and a sulfur content ranging from 0.7% to 3.0%. Southern Appalachia mines are primarily focused on metallurgical markets.

The Interior region includes the Illinois Basin and Gulf Lignite production in Texas and Louisiana, and a small producing area in Kansas, Oklahoma, Missouri and Arkansas. The Illinois Basin is the largest producing region in the Interior and consists of Illinois, Indiana and western Kentucky. According to the EIA, coal produced in the Interior region decreased from 145 million short tons in 2017 to approximately 137 million short tons in 2018. Coal from the Illinois Basin generally has a heat value ranging from 10,100 to 12,600 Btu and has a sulfur content ranging from 1.0% to 4.3%. Despite its high sulfur content, coal from the Illinois Basin can generally be used by electric power generation facilities that have installed emissions control devices, such as scrubbers.

Coal Mining Methods

The geological characteristics of our coal reserves largely determine the coal mining method we employ. We use two primary methods of mining coal: surface mining and underground mining.

Surface Mining. We use surface mining when coal is found close to the surface. We have included the identity and location of our surface mining operations below under “Our Mining Operations-General.” The majority of the coal we produce comes from surface mining operations.

Surface mining involves removing the topsoil then drilling and blasting the overburden (earth and rock covering the coal) with explosives. We then remove the overburden with heavy earth moving equipment, such as draglines, power shovels, excavators and loaders. Once exposed, we drill, fracture and systematically remove the coal using haul trucks or conveyors to transport the coal to a preparation plant or to a loadout facility. We reclaim disturbed areas as part of our normal mining activities. After final coal removal, we use draglines, power shovels, excavators or loaders to backfill the remaining pits with the overburden removed at the beginning of the process. Once we have replaced the overburden and topsoil, we reestablish

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vegetation and plant life into the natural habitat and make other improvements that have local community and environmental benefits.

The following diagram illustrates a typical dragline surface mining operation:

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Underground Mining. We use underground mining methods when coal is located deep beneath the surface. We have included the identity and location of our underground mining operations below under "Our Mining Operations-General." Our underground mines are typically operated using one or both of two different mining techniques: longwall mining and room and pillar mining.

Longwall Mining. Longwall mining involves using a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams. Ultimate seam recovery using longwall mining techniques can exceed 75%. In longwall mining, continuous miners are used to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion. The following diagram illustrates a typical underground mining operation using longwall mining techniques:

Room and Pillar Mining. Room and pillar mining is effective for small blocks of thin coal seams. In room and pillar mining, a network of rooms is cut into the coal seam, leaving a series of pillars of coal to support the roof of the mine. Continuous miners are used to cut the coal and shuttle cars are used to transport the coal to a conveyor belt for further transportation to the surface. The pillars generated as part of this mining method can constitute up to 40% of the total coal in a seam. Higher seam recovery rates can be achieved if retreat mining is used. In retreat mining, coal is mined from the pillars as workers retreat. As retreat mining occurs, the roof is allowed to collapse in a controlled fashion.

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The following diagram illustrates our typical underground mining operation using room and pillar mining techniques:

Coal Preparation and Blending. We crush the coal mined from our Powder River Basin mining complexes and ship it directly from our mines to the customer. Typically, no additional preparation is required for a saleable product. Coal extracted from some of our underground mining operations contains impurities, such as rock, shale and clay occupying a wide range of particle sizes. All of our mining operations in the Appalachia region use a coal preparation plant located near the mine or connected to the mine by a conveyor. These coal preparation plants allow us to treat the coal we extract from those mines to ensure a consistent quality and to enhance its suitability for particular end users. In addition, depending on coal quality and customer requirements, we may blend coal mined from different locations, including coal produced by third parties, in order to achieve a more suitable product.

The treatments we employ at our preparation plants depend on the size of the raw coal. For coarse material, the separation process relies on the difference in the density between coal and waste rock and, for the very fine fractions, the separation process relies on the difference in surface chemical properties between coal and the waste minerals. To remove impurities, we crush raw coal and classify it into various sizes. For the largest size fractions, we use dense media vessel separation techniques in which we float coal in a tank containing a liquid of a pre determined specific gravity. Since coal is lighter than its impurities, it floats, and we can separate it from rock and shale. We treat intermediate sized particles with dense medium cyclones, in which a liquid is spun at high speeds to separate coal from rock. Fine coal is treated in spirals, in which the differences in density between coal and rock allow them, when suspended in water, to be separated. Ultra fine coal is recovered in column flotation cells utilizing the differences in surface chemistry between coal and rock. By injecting stable air bubbles through a suspension of ultra fine coal and rock, the coal particles adhere to the bubbles and rise to the surface of the column where they are removed. To minimize the moisture content in coal, we process most coal sizes through centrifuges. A centrifuge spins coal very quickly, causing water accompanying the coal to separate.

For more information about the locations of our preparation plants, you should see the section entitled “Our Mining Operations.”

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Our Mining Operations

General. At December 31, 2018, we operated 9 active mines in the United States. Our reportable business segments are based on two distinct lines of business, metallurgical coal and thermal coal, and may include a number of mine complexes. We manage our coal sales by market, not by individual mining complex. Geology, coal transportation routes to customers, and regulatory environments also have a significant impact on our marketing and operations management. Our mining operations are evaluated based on Adjusted EBITDAR, per-ton cash operating costs (defined as including all mining costs except depreciation, depletion, amortization, accretion on asset retirements obligations, and pass-through transportation expenses), and on other non-financial measures, such as safety and environmental performance. Adjusted EBITDAR is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization, the amortization of sales contracts, the accretion on asset retirement obligations, and reorganization items, net. Adjusted EBITDAR may also be adjusted for items that may not reflect the trend of future results by excluding transactions that are not indicative of our core operating performance. We use Adjusted EBITDAR to measure the operating performance of our segments and allocate resources to our segments. Adjusted EBITDAR is not a measure of financial performance in accordance with generally accepted accounting principles, and items excluded from Adjusted EBITDAR are significant in understanding and assessing our financial condition. Therefore, Adjusted EBITDAR should not be considered in isolation, nor as an alternative to net income, income from operations, cash flows from operations or as a measure of our profitability, liquidity or performance under generally accepted accounting principles. Furthermore, analogous measures are used by industry analysts to evaluate the Company's operating performance. Investors should be aware that our presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies. Our reportable segments are the Powder River Basin (PRB) segment containing our primary thermal operations in Wyoming; the Metallurgical (MET) segment, containing our metallurgical operations in West Virginia and the Other Thermal segment containing our supplementary thermal operations in Colorado, Illinois, and the Coal Mac thermal operation in West Virginia. For additional information about the operating results of each of our segments for the years ended December 31, 2018 and 2017, the periods October 2 through December 31, 2016 and January 1 through October 1, 2016, see Note 26 to our Consolidated Financial Statements.

In general, we have developed our mining complexes and preparation plants at strategic locations in close proximity to rail or barge shipping facilities. Coal is transported from our mining complexes to customers by means of railroads, trucks, barge lines, and ocean going vessels from terminal facilities. We currently own or lease under long term arrangements all of the equipment utilized in our mining operations. We employ sophisticated preventative maintenance and rebuild programs and upgrade our equipment to ensure that it is productive, well-maintained and cost-competitive.

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The following table provides a summary of information regarding our active mining complexes as of December 31, 2018, including the total sales associated with these complexes for the years ended December 31, 2018 and 2017, and the periods October 2 through December 31, 2016 and January 1 through October 1, 2016 and the total assigned reserves associated with these complexes at December 31, 2018. The amount disclosed below for the total cost of property, plant and equipment of each mining complex does not include the costs of the coal reserves that we have assigned to an individual complex.

Mining Complex	Mines	Mining Equipment	Railroad	Tons Sold[1] Predecessor Jan 1-Oct 1, 2016	Successor Oct 2-Dec 31, 2016	2017	2018	Total Cost of Property, Plant and Equipment at December 31, 2018	Total Assigned Recoverable Reserves
				(Million tons)				($ millions)	(Million tons)
Powder River Basin:									
Black Thunder	S	D, S	UP/BN	49.0	18.9	70.5	71.1	$ 275.7	816.5
Coal Creek	S	D, S	UP/BN	5.5	2.7	9.0	8.0	43.9	94.7
Metallurgical:									
Mountain Laurel	U	LW, CM	CSX	1.2	0.4	1.5	1.9	30.1	11.1
Beckley	U	CM	CSX	0.7	0.3	1.0	1.0	54.5	25.9
Sentinel	U	CM	CSX	0.8	0.3	1.5	1.2	68.0	5.0
Leer	U	LW, CM	CSX	3.1	1.0	3.2	3.5	228.7	29.6
Other Thermal:									
West Elk	U	LW, CM	UP	2.4	1.6	4.9	4.8	42.2	53.9
Viper	U	CM	—	1.3	0.3	1.7	1.8	31.7	43.2
Coal Mac	S	L, E	NS/CSX	1.5	0.5	2.4	2.5	31.3	19.6
Totals				65.5	26.0	95.7	95.8	$ 806.1	1,099.5

S = Surface mine	D = Dragline	UP = Union Pacific Railroad
U = Underground mine	L = Loader/truck	CSX = CSX Transportation
	S = Shovel/truck	BN = Burlington Northern Santa Fe Railway
	E = Excavator/truck	NS = Norfolk Southern Railroad
	LW = Longwall	
	CM = Continuous miner	

(1) Tons of coal we purchased from third parties that were not processed through our loadout facilities are not included in the amounts shown in the table above.

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Powder River Basin

Black Thunder. Black Thunder is a surface mining complex located on approximately 35,800 acres in Campbell County, Wyoming. The Black Thunder complex extracts thermal coal from the Upper Wyodak and Main Wyodak seams.

We control a significant portion of the coal reserves through federal and state leases. The Black Thunder mining complex had approximately 816.5 million tons of proven and probable reserves at December 31, 2018. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of up to 190 million tons per year. Several large tracts of coal adjacent to the Black Thunder mining complex have been nominated for lease, and other potential large areas of unleased coal remain available for nomination by us or other mining operations. The U.S. Department of Interior Bureau of Land Management, which we refer to as the BLM, will determine if the tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts.

The Black Thunder mining complex currently consists of four active pit areas and two active loadout facilities. We ship all of the coal raw to our customers via the Burlington Northern Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. Each of the loadout facilities can load a 15,000 ton train in less than two hours.

Coal Creek. Coal Creek is a surface mining complex located on approximately 7,400 acres in Campbell County, Wyoming. The Coal Creek mining complex extracts thermal coal from the Wyodak R1 and Wyodak R3 seams.

We control a significant portion of the coal reserves through federal and state leases. The Coal Creek mining complex had approximately 94.7 million tons of proven and probable reserves at December 31, 2018. The air quality permit for the Coal Creek mine allows for the mining of coal at a rate of up to 50 million tons per year.

The Coal Creek complex currently consists of one active pit area and a loadout facility. We ship all of the coal raw to our customers via the Burlington Northern Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. The loadout facility can load a 15,000 ton train in less than three hours.

Metallurgical

Mountain Laurel. Mountain Laurel is an underground mining complex located on approximately 38,200 acres in Logan County and Boone County, West Virginia. Underground mining operations at the Mountain Laurel mining complex extract High-vol B metallurgical coal from the Cedar Grove and Alma seams. The Mountain Laurel mining complex has approximately 11.1 million tons of proven and probable reserves at December 31, 2018.

We process all of the coal through a 1,400 ton per hour preparation plant before shipping the coal to our customers via the CSX railroad. The loadout facility can load a 15,000 ton train in less than four hours.

Beckley. The Beckley mining complex is located on approximately 19,700 acres in Raleigh County, West Virginia. Beckley is extracting high quality, low volatile metallurgical coal in the Pocahontas No. 3 seam. The Beckley mining complex had approximately 25.9 million tons of proven and probable reserves at December 31, 2018.

Coal is belted from the mine to a 600 ton per hour preparation plant before shipping the coal via the CSX railroad. The loadout facility can load a 10,000 ton train in less than four hours.

Sentinel. The Sentinel mining complex consists of one underground mine, a preparation plant and a loadout facility located on approximately 25,600 acres in Barbour County, West Virginia. Mining operations currently extract High-vol A metallurgical coal from the Clarion coal seam. Coal from the Sentinel mining complex is processed through the preparation plant and shipped by CSX rail to customers. The Sentinel mining complex had approximately 5.0 million tons of proven and probable reserves at December 31, 2018.

Leer. The Leer Complex, located in Taylor County, West Virginia, includes approximately 29.6 million tons of coal reserves as of December 31, 2018 and has primarily High-vol A metallurgical quality coal in the Lower Kittanning seam, and is part of approximately 82,600 acres that is considered our Tygart Valley area. Substantially all of the reserves at Leer are owned rather than leased from third parties.

All the production is processed through a 1,400 ton per hour preparation plant and loaded on the CSX railroad. A 15,000 ton train can be loaded in less than four hours.

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Leer South. The Leer South mine is an underground, longwall mining operation that we are developing in Barbour County, West Virginia. The mine will consist of three to four continuous miners working in advance of the longwall. Full production will not be realized until the longwall is placed into service in the second half of 2021. All raw coal will be belted and processed through a 1,600 ton-per-hour preparation plant located near the mine. The loadout facility is served by the CSX railroad and is connected to the plant by a 4,000 ton-per-hour conveyor system. The loadout facility will be capable of loading a 15,000 ton unit train in less than four hours. A significant portion of the reserves at Leer South are owned rather than leased from third parties.

Other Thermal

West Elk. West Elk is an underground mining complex located on approximately 18,500 acres in Gunnison County, Colorado. The West Elk mining complex extracts thermal coal from the E seam.

We control a significant portion of the coal reserves through federal and state leases. The West Elk mining complex had approximately 53.9 million tons of proven and probable reserves at December 31, 2018.

The West Elk complex currently consists of a longwall, continuous miner sections and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad. The loadout facility can load an 11,000 ton train in less than three hours.

Viper. The Viper mining complex consists of one underground coal mine and a preparation plant located on approximately 40,600 acres in central Illinois near the city of Springfield. Mining operations extract thermal coal from the Illinois No. 5 seam, also referred to as the Springfield seam. All coal is processed through an 800 ton per hour preparation plant and shipped to customers by on highway trucks.

We control a significant portion of the coal reserves through private leases. As of December 31, 2018, we had approximately 43.2 million tons of proven and probable reserves.

Coal Mac. The surface mining complex is located on approximately 45,800 acres in Logan and Mingo Counties, West Virginia. Surface mining operations at the Coal Mac mining complex extract thermal coal primarily from the Coalburg and Stockton seams.

We control a significant portion of the coal reserves through private leases. The Coal Mac mining complex had approximately 19.6 million tons of proven and probable reserves at December 31, 2018.

The complex currently consists of one captive surface mine, a preparation plant and two loadout facilities, which we refer to as Holden 22 and Ragland. We ship coal trucked to the Ragland loadout facility directly to our customers via the Norfolk Southern railroad. The Ragland loadout facility can load a 10,000 ton train in less than four hours. We ship coal trucked to the Holden 22 loadout facility directly to our customers via the CSX railroad. We wash all of the coal transported to the Holden 22 loadout facility at an adjacent 600 ton per hour preparation plant. The Holden 22 loadout facility can load a 10,000 ton train in about four hours.

Sales, Marketing and Trading

Overview. Coal prices are influenced by a number of factors and can vary materially by region. The price of coal within a region is influenced by market conditions, coal quality, transportation costs involved in moving coal from the mine to the point of use and mine operating costs. For example, higher heat and lower ash content generally result in higher prices, and higher sulfur and higher ash content generally result in lower prices within a given geographic region.

The cost of coal at the mine is also influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. It is generally less expensive to mine coal seams that are thick and located close to the surface than to mine thin underground seams. Within a particular geographic region, underground mining, which is the primary mining method we use in certain of our Appalachian mines, is generally more expensive than surface mining, which is the mining method we use in the Powder River Basin, and for one of our Appalachian mines. This is the case because of the higher capital costs, including costs for construction of extensive ventilation systems, and higher per unit labor costs due to lower productivity associated with underground mining.

Our sales, marketing and trading functions are principally based in St. Louis, Missouri and consist of sales and trading, transportation and distribution, quality control and contract administration personnel as well as revenue management.

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We also have sales representatives in our Singapore and London offices. In addition to selling coal produced from our mining complexes, from time to time we purchase and sell coal mined by others, some of which we blend with coal produced from our mines. We focus on meeting the needs and specifications of our customers rather than just selling our coal production.

Customers. The Company markets its thermal and metallurgical coal to steel producers, domestic and foreign power generators, and other industrial facilities. For the year ended December 31, 2018, we derived approximately 20% of our total coal revenues from sales to our three largest customers, ArcelorMittal, T S Global Procurement Company Pte. and Jera Trading Pte. Ltd. and approximately 41% of our total coal revenues from sales to our 10 largest customers.

In 2018, we sold coal to domestic customers located in 32 different states. The locations of our mines enable us to ship coal to most of the major coal-fueled power plants in the United States.

In addition, in 2018 we also exported coal to Europe, Asia, Central and South America and Africa. Exports to seaborne countries were $1.1 billion, $0.7 billion and $0.4 billion for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018 and 2017, trade receivables related to metallurgical quality coal sales totaled $126.5 million and $99.4 million, respectively, or 63% and 58% of total trade receivables, respectively. We do not have foreign currency exposure for our international sales as all sales are denominated and settled in U.S. dollars.

The Company's seaborne revenues by coal shipment destination for the year ended December 31, 2018, were as follows:

(In thousands)	
Europe	$559,165
Asia	452,711
Central and South America	79,085
Africa	17,567
Brokered Sales	2,372
Total	$1,110,900

Long-Term Coal Supply Arrangements

As is customary in the coal industry, we enter into fixed price, fixed volume long-term supply contracts, the terms of which are more than one year, with many of our customers. Multiple year contracts usually have specific and possibly different volume and pricing arrangements for each year of the contract. Long-term contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2018, we sold approximately 60% of our coal under long-term supply arrangements. The majority of our supply contracts include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our long-term supply agreements may include a variable pricing system. While most of our sales contracts are for terms of one to five years, some are as short as one month and other contracts have terms exceeding five years. At December 31, 2018, the average volume weighted remaining term of our long-term contracts was approximately 2.3 years, with remaining terms ranging from one to four years. At December 31, 2018, remaining tons under long-term supply agreements, including those subject to price re-opener or extension provisions, were approximately 105 million tons.

We typically sell coal to North American customers under long term arrangements through a "request for proposal" process. The terms of our coal sales agreements result from competitive bidding and negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re opener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, force majeure, termination, damages and assignment provisions. Our long term supply contracts typically contain provisions to adjust the base price due to new statutes, ordinances or regulations. We typically sell our metallurgical coal to non-North American customers based on various indices or agreements to mutually negotiate the price. These agreements generally are for one year and can reset pricing with each shipment. Additionally, some of our contracts contain provisions that allow for the recovery of costs affected by modifications or changes in the interpretations or application of any applicable statute by local, state or federal government authorities. These provisions only apply to the base price of coal contained in these supply contracts. In some circumstances, a

significant adjustment in base price can lead to termination of the contract.
Certain of our contracts contain index provisions that change the price based on changes in market based indices or changes in economic indices or both. Certain of our contracts contain price re opener provisions that may allow a party to

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commence a renegotiation of the contract price at a pre determined time. Price re opener provisions may automatically set a new price based on prevailing market price or, in some instances, require us to negotiate a new price, sometimes within a specified range of prices. In a limited number of agreements, if the parties do not agree on a new price, either party has an option to suspend the agreement for the pricing period not agreed to. In addition, certain of our contracts contain clauses that may allow customers to terminate the contract in the event of certain changes in environmental laws and regulations that impact their operations.

Coal quality and volumes are stipulated in coal sales agreements. In most cases, the annual pricing and volume obligations are fixed, although in some cases the volume specified may vary depending on the customer consumption requirements. Most of our coal sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content (for thermal coal contracts), volatile matter (for metallurgical coal contracts), and for both types of contracts, sulfur, ash and moisture content. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Our coal sales agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or our customers, during the duration of events beyond the control of the affected party, including events such as strikes, adverse mining conditions, mine closures or serious transportation problems that affect us or unanticipated plant outages that may affect the buyer. Our contracts also generally provide that in the event a force majeure circumstance exceeds a certain time period, the unaffected party may have the option to terminate the purchase or sale in whole or in part. Some contracts stipulate that this tonnage can be made up by mutual agreement or at the discretion of the buyer. Agreements between our customers and the railroads servicing our mines may also contain force majeure provisions.

In most of our thermal coal contracts, we have a right of substitution (unilateral or subject to counterparty approval), allowing us to provide coal from different mines, including third party mines, as long as the replacement coal meets quality specifications and will be sold at the same equivalent delivered cost.

In some of our coal supply contracts, we agree to indemnify or reimburse our customers for damage to their or their rail carrier’s equipment while on our property, which results from our or our agents’ negligence, and for damage to our customer’s equipment due to non coal materials being included with our coal while on our property.

Trading. In addition to marketing and selling coal to customers through traditional coal supply arrangements, we seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of other marketing, trading and asset optimization strategies. From time to time, we may employ strategies to use coal and coal related commodities and contracts for those commodities in order to manage and hedge volumes and/or prices associated with our coal sales or purchase commitments, reduce our exposure to the volatility of market prices or augment the value of our portfolio of traditional assets. These strategies may include physical coal contracts, as well as a variety of forward, futures or options contracts, swap agreements or other financial instruments.

We maintain a system of complementary processes and controls designed to monitor and manage our exposure to market and other risks that may arise as a consequence of these strategies. These processes and controls seek to preserve our ability to profit from certain marketing, trading and asset optimization strategies while mitigating our exposure to potential losses. You should see Item 7A, entitled “Quantitative and Qualitative Disclosures About Market Risk” for more information about the market risks associated with these strategies at December 31, 2018.

Transportation. We ship our coal to domestic customers by means of railcars, barges, or trucks, or a combination of these means of transportation. We generally sell coal used for domestic consumption free on board (f.o.b.) at the mine or nearest loading facility. Our domestic customers normally bear the costs of transporting coal by rail, barge or truck. Historically, most domestic electricity generators have arranged long term shipping contracts with rail, trucking or barge companies to assure stable delivery costs. Transportation can be a large component of a purchaser’s total cost. Although the purchaser pays the freight, transportation costs still are important to coal mining companies because the purchaser may choose a supplier largely based on cost of transportation. Transportation costs borne by the customer vary greatly based on each customer’s proximity to the mine and our proximity to the loadout facilities. Trucks and overland conveyors haul coal over shorter distances, while barges, Great Lake carriers and ocean vessels move coal to export markets and domestic markets requiring shipment over the Great Lakes and several river systems.

Most coal mines are served by a single rail company, but much of the Powder River Basin is served by two rail carriers: the Burlington Northern Santa Fe railroad and the Union Pacific railroad; and our Coal Mac mine is served by both the CSX and Norfolk Southern railroads. We generally transport coal produced at our Appalachian mining complexes via the

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CSX railroad or the Norfolk Southern railroad. Besides rail deliveries, some customers in the eastern United States rely on a river barge system.

We generally sell coal to international customers at an export terminal, and we are usually responsible for the cost of transporting coal to the export terminals. We transport our coal to Atlantic coast terminals, Pacific cost terminals or terminals along the Gulf of Mexico for transportation to international customers. Our international customers are generally responsible for paying the cost of ocean freight. We may also sell coal to international customers delivered to an unloading facility at the destination country.

We own a 35% interest in Dominion Terminal Associates, a partnership that operates a ground storage to vessel coal transloading facility in Newport News, Virginia. The facility has a rated throughput capacity of 20 million tons of coal per year and ground storage capacity of approximately 1.7 million tons. The facility primarily serves international customers, as well as domestic coal users located along the Atlantic coast of the United States. From time-to-time, we may lease a portion of our port capacity to third parties.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality, delivered costs to the customer and reliability of supply. Our principal domestic competitors include Blackhawk Mining LLC, Blackjewel LLC, Contura Energy, Coronado Coal LLC, Corsa Coal Corp., Cloud Peak Energy, Peabody Energy Corp., Ramaco Resources and Warrior Met Coal, Inc. Some of these coal producers are larger than we are and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in each of the geographic regions in which we operate, as well as companies that produce coal from one or more foreign countries, such as Australia, Colombia, Indonesia and South Africa.

Additionally, coal competes with other fuels, such as natural gas, nuclear energy, hydropower, wind, solar and petroleum, for steam and electrical power generation. Costs and other factors relating to these alternative fuels, such as safety and environmental considerations, as well as tax incentives and various mandates, affect the overall demand for coal as a fuel.

Suppliers

Principal supplies used in our business include petroleum based fuels, explosives, tires, steel and other raw materials as well as spare parts and other consumables used in the mining process. We use third party suppliers for a significant portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business such as explosives and fuel, and preferred suppliers for other parts of our business such as original equipment suppliers, dragline and shovel parts and related services. We believe adequate substitute suppliers are available. For more information about our suppliers, you should see Item 1A, “Risk Factors-Increases in the costs of mining and other industrial supplies, including steel based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production.”

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety and the environment, including the protection of air quality, water quality, wetlands, special status species of plants and animals, land uses, cultural and historic properties and other environmental resources identified during the permitting process. Reclamation is required during production and after mining has been completed. Materials used and generated by mining operations must also be managed according to applicable regulations and law. These laws have, and will continue to have, a significant effect on our production costs and our competitive position. We endeavor to conduct our mining operations in compliance with applicable federal, state and local laws and regulations. However, due in part to the extensive, comprehensive and changing regulatory requirements, violations during mining operations occur from time to time. We cannot assure you that we have been or will be at all times in complete compliance with such laws and regulations. Expenditures we incur to maintain compliance with all applicable federal and state laws have been and are expected to continue to be significant. Federal and state mining laws and regulations require us to obtain surety bonds to guarantee performance or payment of certain long term obligations, including mine closure and reclamation costs, federal and state workers’ compensation benefits, coal leases and other miscellaneous obligations. Compliance with these laws has substantially increased the cost of coal mining for domestic coal producers.

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Future laws, regulations or orders, as well as future interpretations and more rigorous enforcement of existing laws, regulations or orders, may require substantial increases in equipment and operating costs and delays, interruptions or a termination of operations, the extent to which we cannot predict. Future laws, regulations or orders may also cause coal to become a less attractive fuel source, thereby reducing coal's share of the market for fuels and other energy sources used to generate electricity. As a result, future laws, regulations or orders may adversely affect our mining operations, cost structure or our customers' demand for coal.

The following is a summary of the various federal and state environmental and similar regulations that have a material impact on our business:

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. When we apply for these permits and approvals, we may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. For example, in order to obtain a federal coal lease, an environmental impact statement must be prepared to assist the BLM in determining the potential environmental impact of lease issuance, including any collateral effects from the mining, transportation and burning of coal, which may in some cases include a review of impacts on climate change. The authorization, permitting and implementation requirements imposed by federal, state and local authorities may be costly and time consuming and may delay commencement or continuation of mining operations. In the states where we operate, the applicable laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if officers, directors, shareholders with specified interests or certain other affiliated entities with specified interests in the applicant or permittee have, or are affiliated with another entity that has, outstanding permit violations. Thus, past or ongoing violations of applicable laws and regulations could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from federal and state regulatory authorities, mine operators must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition or other authorized use. Typically, we submit the necessary permit applications several months or even years before we plan to begin mining a new area. Some of our required permits are becoming increasingly more difficult and expensive to obtain, and the application review processes are taking longer to complete and becoming increasingly subject to challenge, even after a permit has been issued.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, which we refer to as SMCRA, establishes mining, environmental protection, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. Mining operators must obtain SMCRA permits and permit renewals from the Office of Surface Mining, which we refer to as OSM, or from the applicable state agency if the state agency has obtained regulatory primacy. A state agency may achieve primacy if the state regulatory agency develops a mining regulatory program that is no less stringent than the federal mining regulatory program under SMCRA. All states in which we conduct mining operations have achieved primacy and issue permits in lieu of OSM.

SMCRA permit provisions include a complex set of requirements which include, among other things, coal prospecting; mine plan development; topsoil or growth medium removal and replacement; selective handling of overburden materials; mine pit backfilling and grading; disposal of excess spoil; protection of the hydrologic balance; subsidence control for underground mines; surface runoff and drainage control; establishment of suitable post mining land uses; and revegetation. We begin the process of preparing a mining permit application by collecting baseline data to adequately characterize the pre mining environmental conditions of the permit area. This work is typically conducted by third party consultants with specialized expertise and includes surveys and/or assessments of the following: cultural and historical resources; geology; soils; vegetation; aquatic organisms; wildlife; potential for threatened, endangered or other special status species; surface and ground water hydrology; climatology; riverine and riparian habitat; and wetlands. The geologic data and information derived from the other surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application. The mining and reclamation plans address the provisions and performance standards of the state's equivalent SMCRA regulatory program, and are also used to support applications for other authorizations and/or permits required to conduct coal mining activities. Also included in the permit application is information used for documenting surface and mineral ownership, variance requests, access roads, bonding information, mining methods, mining phases, other agreements that may relate to coal, other minerals, oil and gas rights, water rights, permitted areas, and ownership and control information required to determine compliance with OSM's Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

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Once a permit application is prepared and submitted to the regulatory agency, it goes through an administrative completeness review and a thorough technical review. Also, before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of all reclamation obligations. After the application is submitted, a public notice or advertisement of the proposed permit is required to be given, which begins a notice period that is followed by a public comment period before a permit can be issued. It is not uncommon for a SMCRA mine permit application to take over a year to prepare, depending on the size and complexity of the mine, and anywhere from six months to two years or even longer for the permit to be issued. The variability in time frame required to prepare the application and issue the permit can be attributed primarily to the various regulatory authorities' discretion in the handling of comments and objections relating to the project received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of litigation related to the specific permit or another related company's permit.

In addition to the bond requirement for an active or proposed permit, the Abandoned Mine Land Fund, which was created by SMCRA, requires that a fee be paid on all coal produced. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA's adoption in 1977, as well as fund other state and federal initiatives. The current fee is $0.28 per ton of coal produced from surface mines and $0.12 per ton of coal produced from underground mines. In 2018, we recorded $24.4 million of expense related to these reclamation fees.

Surety Bonds. Mine operators are often required by federal and/or state laws, including SMCRA, to assure, usually through the use of surety bonds, payment of certain long term obligations including mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other miscellaneous obligations. Although surety bonds are usually noncancelable during their term, many of these bonds are renewable on an annual basis and collateral requirements may change.

The costs of these bonds have widely fluctuated in recent years while the market terms of surety bonds have generally hardened for mine operators. These changes in the terms of the bonds have been accompanied at times by a decrease in the number of companies willing to issue surety bonds. As of December 31, 2018, we posted an aggregate of approximately $536.2 million in surety bonds for reclamation purposes. In addition, we had approximately $157.6 million of surety bonds, cash and letters of credit outstanding at December 31, 2018 to secure workers' compensation, coal lease and other obligations.

For additional information, please see "Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal, and a loss or reduction in our ability to self-bond could have a material, adverse effect on our business and results of operations," contained in Item 1A, "Risk Factors—Risk Related to Our Operations," for a discussion of certain risks associated with our surety bonds.

Mine Safety and Health. Stringent safety and health standards have been imposed by federal legislation since Congress adopted the Mine Safety and Health Act of 1969. The Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed comprehensive safety and health standards on all aspects of mining operations. In addition to federal regulatory programs, all of the states in which we operate also have programs aimed at improving mine safety and health. Collectively, federal and state safety and health regulation in the coal mining industry is among the most comprehensive and pervasive systems for the protection of employee health and safety affecting any segment of U.S. industry.

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and 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. The trust fund is funded by an excise tax on production of up to $1.10 per ton for coal mined in underground operations and up to $0.55 per ton for coal mined in surface operations. These amounts may not exceed 4.4% of the gross sales price. This excise tax does not apply to coal shipped outside the United States. In 2018, we recorded $44.3 million of expense related to this excise tax.

Clean Air Act. The federal Clean Air Act and similar state and local laws that regulate air emissions affect coal mining directly and indirectly. Direct impacts on coal mining and processing operations include Clean Air Act permitting requirements and emissions control requirements relating to particulate matter which may include controlling fugitive dust. The Clean Air Act also indirectly affects coal mining operations, for example, by extensively regulating the emissions of fine particulate matter measuring 2.5 micrometers in diameter or smaller, sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal fueled power plants and industrial boilers, which are the largest end users of our coal. Already stringent regulation of emissions further tightened throughout the Obama Administration, such as the Mercury and Air Toxics Standard (MATS), finalized in 2011 and discussed in more detail below. In addition, the U.S. Environmental Protection Agency, which we refer to as the EPA, has issued regulations with respect to other emissions, such as greenhouse gases (GHG's), from new,

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modified, reconstructed and existing electric generating units, including coal-fired plants. Other GHG regulations apply to industrial boilers (see discussion of Climate Change, below). Although the Trump Administration has proposed repealing or loosening a number of these regulations as described below, it is unclear the degree to which these proposals will take effect, or to what extent they will survive into future Administrations. Collectively, regulations of air emissions, as well as uncertainty regarding the future course of regulation could eventually reduce the demand for coal.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

- Acid Rain. Title IV of the Clean Air Act, promulgated in 1990, imposed a two phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and applies to all coal fueled power plants with a capacity of more than 25 megawatts. Generally, the affected power plants have sought to comply with these requirements by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing or trading sulfur dioxide emissions allowances. Although we cannot accurately predict the future effect of this Clean Air Act provision on our operations, we believe that implementation of Phase II has been factored into the pricing of the coal market.

- Particulate Matter. The Clean Air Act requires the EPA to set national ambient air quality standards, which we refer to as NAAQS, for certain pollutants associated with the combustion of coal, including sulfur dioxide, particulate matter, nitrogen oxides and ozone. Areas that are not in compliance with these standards, referred to as non attainment areas, must take steps to reduce emissions levels. For example, NAAQS currently exist for particulate matter measuring 10 micrometers in diameter or smaller (PM10) and for fine particulate matter measuring 2.5 micrometers in diameter or smaller (PM2.5), and the EPA revised the PM2.5 NAAQS on December 14, 2012, making it more stringent. The states were required to make recommendations on nonattainment designations for the new NAAQS in late 2013. The EPA issued final designations for most areas of the country in 2012 and made some revisions in 2015. Individual states must now identify the sources of emissions and develop emission reduction plans. These plans may be state specific or regional in scope. Under the Clean Air Act, individual states have up to 12 years from the date of designation to secure emissions reductions from sources contributing to the problem. Future regulation and enforcement of the new PM2.5 standard, as well as future revisions of PM standards, will affect many power plants, especially coal fueled power plants, and all plants in non attainment areas.

- Ozone. On October 26, 2015, the EPA published a final rule revising the existing primary and secondary NAAQS for ozone, reducing them to 70ppb on an 8-hour average. On November 17, 2016, the EPA issued a proposed implementation rule on non-attainment area classification an state implementation plans (SIPs). The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 35% of the U.S. counties, designating them as either “attainment/unclassifiable” or “unclassifiable.” In April 2018 and July 2018, the EPA issued ozone designations for all areas not addressed in the November 2017 rule. States with moderate or high nonattainment areas must submit SIPs by October 2021.

Significant additional emission control expenditures will likely be required at certain coal fueled power plants to meet the new stricter NAAQS. Nitrogen oxides, which are a byproduct of coal combustion, are classified as an ozone precursor. As a result, emissions control requirements for new and expanded coal fueled power plants and industrial boilers will continue to become more demanding in the years ahead. A suit challenging the EPA’s 2015 Ozone NAAQS, Murray Energy Corp. v. EPA, is currently pending in the United States Court of Appeals for the District of Columbia, which we refer to as the D.C. Circuit. However, on April 11, 2017, the D.C. Circuit granted the EPA’s motion, which cites President Trump’s March 28, 2017 Energy Independence Executive Order, to indefinitely delay any decision on the challenges. In August 2018, the EPA informed the Court that the EPA would not revisit the 2015 Ozone NAAQS, and the litigation stay was lifted. On December 6, 2018, the EPA issued a Final Rule implementing the 2015 Ozone NAAQS for nonattainment areas (“2015 Ozone Implementation Rule”). The 2015 Ozone Implementation Rule is notable for providing greater flexibility to States to consider international sources of pollution and other mechanisms for relief from strict application of the standard. With such flexibility, the effect on demand for coal will vary by state.

- NOx SIP Call. The Nitrogen Oxides State Implementation Plan (NOx SIP) Call program was established by the EPA in October 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said that they could not meet federal air quality standards because of migrating pollution. The program was designed to reduce nitrous oxide emissions by one million tons per year in 22 eastern states and the District of Columbia. Phase II reductions were required by May 2007. As a result of the program, many power plants were required to install additional emission control measures, such as selective catalytic reduction devices.

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Installation of additional emission control measures has made it more costly to operate coal fueled power plants, which could make coal a less attractive fuel.

- Interstate Transport. The EPA finalized the Clean Air Interstate Rule, which we refer to as CAIR, in March 2005. CAIR called for power plants in 28 Eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide, which could lead to non-attainment of PM2.5 and ozone NAAQS in downwind states (interstate transport), pursuant to a cap and trade program similar to the system now in effect for acid deposition control. In July 2008, in State of North Carolina v. EPA and consolidated cases, the D.C. Circuit disagreed with the EPA's reading of the Clean Air Act and vacated CAIR in its entirety. In December 2008, the D.C. Circuit revised its remedy and remanded the rule to the EPA. The EPA proposed a revised transport rule on August 2, 2010 (75 Fed. Reg. 45209) to address attainment of the 1997 ozone NAAQS and the 2006 PM2.5 NAAQS. The rule was finalized as the Cross State Air Pollution Rule (CSAPR) on July 6, 2011, with compliance required for SO2 reductions beginning January 1, 2012 and compliance with NOx reductions required by May 1, 2012. Numerous appeals of the rule were filed and, on August 21, 2012, the D.C. Circuit vacated the rule, leaving the EPA to continue implementation of the CAIR. Controls required under the CAIR, especially in conjunction with other rules may have affected the market for coal inasmuch as multiple existing coal fired units were being retired rather than having required controls installed.

The U.S. Supreme Court agreed to hear the EPA's appeal of the decision vacating CSAPR and on April 29, 2014, issued an opinion reversing the August 21, 2012 D.C. Circuit decision, remanding the case back to the D.C. Circuit. The EPA then requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the EPA's request, and that court later dismissed all pending challenges to the rule on July 28, 2015 but it remanded some state budgets to the EPA for further consideration. CSAPR Phase 1 implementation began in 2015, with Phase 2 beginning in 2017. CSAPR generally requires greater reductions than under CAIR. As a result, some coal fired power plants will be required to install costly pollution controls or shut down which may adversely affect the demand for coal. Finally, in October 2016, the EPA issued an update to the CSAPR to address interstate transport of air pollution under the more recent 2008 ozone NAAQS and the state budgets remanded by the D.C. Circuit. Consolidated judicial challenges to the rule are now pending, but on August 10, 2017, the D.C. Circuit suspended briefing in the litigation after industry petitioners challenging the rule requested to delay proceedings so the EPA can determine whether to reconsider the revised CSAPR. On June 29, 2018, the EPA issued a proposed determination that the 2016 CSAPR Update Rule fully addresses states' interstate transport obligations under the 2008 ozone NAAQS. However, the EPA has also signaled in a variety of 2018 memoranda that states may have more flexibility to consider international emissions and higher thresholds in developing SIPS than under prior guidance. It is not clear how the combination of upholding the 2016 CSAPR Update Rule while allowing greater SIP flexibility will affect decisions to install controls or shut down units, and any resulting effects on the demand for coal. The uncertainty itself may adversely affect demand.

- Mercury. In February 2008, the D.C. Circuit vacated the EPA's Clean Air Mercury Rule (CAMR), which was promulgated to reduce mercury emissions from coal-fired power plants and remanded it to the EPA for reconsideration. In response, the EPA announced an Electric Generating Unit (EGU) Mercury and Air Toxics Standard (MATS) on December 16, 2011. The MATS was finalized April 16, 2012, and required compliance for most plants by 2015. In addition, before the court decision vacating the CAMR, some states had either adopted the CAMR or adopted state specific rules to regulate mercury emissions from power plants that are more stringent than the CAMR. MATS compliance, coupled with state mercury and air toxics laws and other factors have required many plants to install costly controls, re-fire with natural gas or to retire, which may adversely affect the demand for coal.

MATS was challenged in the D.C. Circuit, which upheld the rule on April 15, 2013. Petitioners successfully obtained Supreme Court review, and on June 29, 2015, the Supreme Court issued a 5-4 decision striking down the final rule based on the EPA's failure to consider economic costs in determining whether to regulate. The case was remanded to the D.C. Circuit. The EPA began reconsideration of costs, and petitioners unsuccessfully sought a stay of the rule in the Supreme Court in February 2016. In April 2016, the EPA issued a MATS 2016 Supplemental Finding, a final finding that it is appropriate and necessary to set standards for emissions of air toxics from coal- and oil-fired power plants. That finding is now being challenged in court. Therefore, the rule remains in effect until further order of the D.C. Circuit. The D.C. Circuit denied petitioners' motion to temporarily halt the pending litigation to allow the new administration to evaluate whether it can resolve any issues raised in the case. However, in April 2017, the EPA requested a delay in the D.C. Circuit proceedings while the EPA is reviewing the determinations of the prior administration. On December 27, 2018, the EPA

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released a Supplemental Cost Finding, concluding that direct regulation of air toxics from coal- and oil-fired power plants is not cost-justified, but proposing to leave the emissions standards and other requirements of the 2012 rule in place.

- Regional Haze. The EPA has initiated a regional haze program designed to protect and improve visibility at and around national parks, national wilderness areas and international parks, particularly those located in the southwest and southeast United States. Under the Regional Haze Rule, affected states were required to submit regional haze SIPs by December 17, 2007, that, among other things, were to identify facilities that would have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by December 17, 2007, and the EPA issued a Finding of Failure to Submit plans on January 15, 2009 (74 Fed. Reg. 2392). The EPA had taken no enforcement action against states to finalize implementation plans and was slowly dealing with the state Regional Haze SIPs that were submitted, which resulted in the National Parks Conservation Association commencing litigation in the D.C. Circuit on August 3, 2012, against the EPA for failure to enforce the rule (National Parks Conservation Act v. EPA, D.C. Cir). Industry groups, including the Utility Air Regulatory Group intervened.

The EPA ultimately agreed in a consent decree with environmental groups to impose regional haze federal implementation plans (FIPs) or to take action on regional haze SIPs before the agency for 42 states and the District of Columbia. The EPA has completed those actions for all but several states in its first planning period (2008-2010). In many eastern states, the EPA has allowed states to meet “best available retrofit control technology” (BART) requirements for power plants through compliance with CAIR and CSAPR (a policy under pending litigation). Other states have had BART imposed on a case-by-case basis, and where the EPA found SIPs deficient, it disapproved them and issued FIPs. It is possible that the EPA may continue to increase the stringency of control requirements imposed under the Regional Haze Program as it moves toward the next planning period, which could be delayed until 2021.

This program may result in additional emissions restrictions from new coal fueled power plants whose operations may impair visibility at and around federally protected areas. This program may also require certain existing coal fueled power plants to install additional control measures designed to limit haze causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could affect the future market for coal. However, on January 18, 2018, the EPA announced that it was revisiting the 2017 Regional Haze Rule revisions, and announced an intent to commence a new rulemaking. On September 11, 2018, the EPA released a “Regional Haze Reform Roadmap” and reaffirmed its commitment to additional rulemaking.
This proceeding may slow or even roll back certain Regional Haze requirements.

- New Source Review. A number of pending regulatory changes and court actions are affecting the scope of the EPA’s new source review program, which under certain circumstances requires existing coal fueled power plants to install the more stringent air emissions control equipment required of new plants. The new source review program is continually revised and such revisions may impact demand for coal nationally.

Climate Change. Carbon dioxide, which is defined to be a greenhouse gas, is a by-product of burning coal. Global climate issues, including with respect to greenhouse gases such as carbon dioxide and the relationship that greenhouse gases may have with perceived global warming, continue to attract significant public and scientific attention. For example, the Fourth and Fifth Assessment Reports of the Intergovernmental Panel on Climate Change have expressed concern about the impacts of human activity, especially from fossil fuel combustion, on global climate issues. As a result of the public and scientific attention, several governmental bodies increasingly are focusing on global climate issues and, more specifically, levels of emissions of carbon dioxide from coal combustion by power plants. Future regulation of greenhouse gas emissions in the United States could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes and the federal, state or local level or otherwise.
Demand for coal also may be impacted by international efforts to reduce emissions of greenhouse gases. For example, in December 2015, representatives of 195 nations reached a climate accord that will, for the first time, commit

participating countries to lowering greenhouse gas emissions. Further, the United States and a number of international development banks, such as the World Bank, the European Investment Bank and European Bank for Reconstruction and Development, have announced that they will no longer provide financing for the development of new coal-fueled power plants, subject to very narrow exceptions.

Although the U.S. Congress has considered various legislative proposals that would address global climate issues and greenhouse gas emissions, no such federal proposals have been adopted into law to date. In the absence of U.S. federal

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legislation on these topics, the U.S. Environmental Protection Agency (the “EPA”) has been the primary source of federal oversight, although future regulation of greenhouse gases and global climate matters in the United States could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes under the Clean Air Act, federal adoption of a greenhouse gas regulatory scheme or otherwise.

In 2007, the U.S. Supreme Court held that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. Although the Supreme Court’s holding did not expressly involve the EPA’s authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the EPA since has determined on its own that it has the authority to regulate greenhouse gas emissions from power plants, and the EPA has published a formal determination that six greenhouse gases, including carbon dioxide, endanger both the public health and welfare of current and future generations.

In 2014, the EPA proposed a sweeping rule, known as the “Clean Power Plan,” to cut carbon emissions from existing electric generating units, including coal-fired power plants. A final version of the Clean Power Plan was adopted in August 2015. The final version of the Clean Power Plan aims to reduce carbon dioxide emissions from electrical power generation by 32% by 2030 relative to 2005 levels through reduction of emissions from coal-burning power plants and increased use of renewable energy and energy conservation methods. Under the Clean Power Plan, states are free to reduce emissions by various means and must submit emissions reduction plans to the EPA by September 2016 or, with an approved extension, September 2018. If a state has not submitted a plan by then, the Clean Power Plan authorizes the EPA to impose its own plan on that state. In order to determine a state’s goal, the EPA has divided the country into three regions based on connected regional electricity grids. States are to implement their plans by focusing on (i) increasing the generation efficiency of existing fossil fuel plants, (ii) substituting lower carbon dioxide emitting natural gas generation for coal-powered generation and (iii) substituting generation from new zero carbon dioxide emitting renewable sources for fossil fuel powered generation. States are permitted to use regionally available low carbon generation sources when substituting for in-state coal generation and coordinate with other states to develop multi-state plans. Following the adoption, 27 states sued the EPA, claiming that the EPA overstepped its legal authority in adopting the Clean Power Plan. In February 2016, the U.S. Supreme Court ordered the EPA to halt enforcement of the Clean Power Plan until a lower court rules on the lawsuit and until the Supreme Court determines whether or not to hear the case. In October 2017, the EPA commenced rulemaking proceedings to rescind the Clean Power Plan, and in December 2017, the EPA published an Advanced Notice of Proposed Rulemaking announcing an intent to commence a new rulemaking to replace the Clean Power Plan with an alternative framework for regulating carbon dioxide.

In a parallel litigation, 25 states and other parties filed lawsuits challenging the EPA’s final New Source Performance Standards rules, which we refer to as NSPS, for carbon dioxide emissions from new, modified, and reconstructed power plants under the Clean Air Act. One of the primary issues in these lawsuits is the EPA’s establishment of standards of performance based on technologies including carbon capture and sequestration, which we refer to as CCS. New coal plants cannot meet the new standards unless they implement CCS, which reportedly is not yet commercially available or technically feasible. In conjunction with the EPA’s proposal to rescind the Clean Power Plan, the EPA also requested a stay of the NSPS litigation. The D.C. Circuit granted the request, and the litigation has been held in abeyance since then.

On August 21, 2018, the EPA proposed the Affordable Clean Energy (ACE) rule as a replacement for the Clean Power Plan. The ACE rule would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE rule has several components: a determination of the best system of emission reduction for greenhouse gas emissions from coal-fired power plants, a list of “candidate technologies” states can use when developing their plans, a new preliminary applicability test for determining whether a physical or operational change made to a power plant may be a “major modification” triggering New Source Review, and new implementing regulations for emission guidelines under Clean Air Act section 111(d). If implemented as proposed, the ACE rule would reduce the regulatory burden from the Clean Power Plan and NSPS for new, modified and reconstructed power plant. This could increase demand for coal, but the ACE rule will likely be subject to

litigation and its ultimate effect on demand is unknown.
In December 2015, 195 nations (including United States) signed the Paris Agreement, a long-term, international framework convention designed to address climate change over the next several decades. This agreement entered into force in November 2016 after more than 70 countries, including the United States, ratified or otherwise agreed to be bound by the agreement. The United States was among the countries that submitted its declaration of intended greenhouse gas reductions in early 2015, stating its intention to reduce U.S. greenhouse gas emissions by 26-28% by 2025 compared to 2005 levels. Whether and to what extent the United States meets its stated intention likely depends on several factors, including whether the ACE rule is implemented. On June 1, 2017, The Trump Administration announced the United States intends to withdraw from the Paris Agreement. Regardless of the extent to which the United States ultimately participates in these reductions, over the long term, international participation in the Paris Agreement framework could reduce overall demand for coal which could have a material

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adverse impact on us. These effects could be more adverse to the extent the United States ultimately participates in these reductions (whether via the Paris Agreement or otherwise).

Several U.S. states have enacted legislation establishing greenhouse gas emissions reduction goals or requirements or joined regional greenhouse gas reduction initiatives. Some states also have enacted legislation or 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. For example, nine northeastern states currently are members of the Regional Greenhouse Gas Initiative, which is a mandatory cap-and-trade program established in 2005 to cap regional carbon dioxide emissions from power plants. Six midwestern states and one Canadian province entered into the Midwestern Regional Greenhouse Gas Reduction Accord to establish voluntary regional greenhouse gas reduction targets and develop a voluntary multi-sector cap-and-trade system to help meet the targets, although it has been reported that the members no longer are actively pursuing the group’s activities. Lastly, California and Quebec remain members of the Western Climate Initiative, which was formed in 2008 to establish a voluntary regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions, and those two jurisdictions have adopted their own greenhouse gas cap-and-trade regulations. Several states and provinces that originally were members of these organizations, as well as some current members, have joined the new North America 2050 initiative, which seeks to reduce greenhouse gas emissions and create economic opportunities aside from cap-and-trade programs. Any particular state, or any of these or other regional group, may have or adopt in the future rules or policies that cause some users of coal to switch from coal to a lower carbon fuel. There can be no assurance at this time that a carbon dioxide cap-and-trade-program, a carbon tax or other regulatory or policy regime, if implemented by any one or more states or regions in which our customers operate or at the federal level, will not affect the future market for coal in those states or regions and lower the overall demand for coal.

Clean Water Act. The federal Clean Water Act (sometimes shortened to CWA) and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including dredged and fill materials, into waters of the United States. The Clean Water Act provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Recent court decisions and regulatory actions have created uncertainty over Clean Water Act jurisdiction and permitting requirements that could variously increase or decrease the cost and time we expend on Clean Water Act compliance. The scope of waters that fall within the Clean Water Act’s jurisdiction is expansive and may include features not commonly understood to be a stream or wetland. In June 2015, the EPA issued a new rule defining the scope of "waters of the United States" (WOTUS) that are subject to regulation. The WOTUS rule was challenged by a number of states and private parties in both district and circuit courts. The actions in the circuit courts were consolidated in the United States Court of Appeals for the Sixth Circuit and in October 2015 that court stayed the WOTUS rule on a nationwide basis. In January 2018, the Supreme Court ruled that challenges to the WOTUS rule must be made to the appropriate federal district courts rather than the Sixth Circuit. The Supreme Court’s ruling caused the Sixth Circuit to lift the nationwide stay. The EPA and the Corps proposed a rule in February 2018 to suspend implementation of the 2015 WOTUS Rule until 2020. This proposed rule reinstated the WOTUS definition that had been applied prior to 2015. Two federal district courts have enjoined the two-year suspension, which has resulted in a split between states where the 2015 WOTUS Rule has been stayed and those in which the 2015 Rule remains in effect. There are currently twenty-eight states in which the stay applies and the pre-2015 definition of WOTUS is in effect and twenty-two states that observe the 2015 WOTUS Rule. In December 2017, the EPA and the Corps proposed a rule to repeal the WOTUS rule. The EPA and Corps formally proposed a rule revising the definition of “Waters of the United States” in December 2018. The proposed definition would substantially reduce the scope of waters that fall within the Clean Water Act’s jurisdiction, in part by excluding ephemeral streams. The EPA and the Corps had previously determined that ephemeral streams could potentially qualify as “Waters of the United States,” which would not be possible under the proposed definition.

Clean Water Act requirements that may directly or indirectly affect our operations include the following:

- Water Discharge. Section 402 of the Clean Water Act creates a process for establishing effluent limitations for discharges to streams that are protective of water quality standards through the National Pollutant Discharge Elimination System, which we refer to as the NPDES, or an equally stringent program delegated to a state regulatory agency. Regular monitoring, reporting and compliance with performance standards are preconditions for the issuance and renewal of NPDES permits that govern discharges into waters of the United States, especially on selenium, sulfate and specific conductance. Discharges that exceed the limits specified under NPDES permits can lead to the imposition of penalties, and persistent non compliance could lead to significant penalties, compliance costs and delays in coal production. In addition, the imposition of future restrictions on the discharge of certain pollutants into waters of the United States could increase the difficulty of obtaining and complying with

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NPDES permits, which could impose additional time and cost burdens on our operations. You should see Item 3, “Legal Proceedings,” for more information about certain regulatory actions pertaining to our operations.

Discharges of pollutants into waters that states have designated as impaired (i.e., as not meeting present water quality standards) are subject to Total Maximum Daily Load, which we refer to as TMDL, regulations. The TMDL regulations establish a process for calculating the maximum amount of a pollutant that a water body can receive while maintaining state water quality standards. Pollutant loads are allocated among the various sources that discharge pollutants into that water body. Mine operations that discharge into water bodies designated as impaired will be required to meet new TMDL allocations. The adoption of more stringent TMDL related allocations for our coal mines could require more costly water treatment and could adversely affect our coal production.

The Clean Water Act also requires states to develop anti degradation policies to ensure that non impaired water bodies continue to meet water quality standards. The issuance and renewal of permits for the discharge of pollutants to waters that have been designated as “high quality” are subject to anti degradation review that may increase the costs, time and difficulty associated with obtaining and complying with NPDES permits.

Under the Clean Water Act, citizens may sue to enforce NPDES permit requirements. Beginning in 2012, multiple citizens’ suits were filed in West Virginia against mine operators for alleged violations of NPDES permit conditions requiring compliance with West Virginia’s water quality standards. Some of the lawsuits alleged violations of water quality standards for selenium, whereas others alleged that discharges of conductivity and sulfate were causing violations of West Virginia water quality standards that prohibit adverse effects to aquatic life. The suits sought penalties as well as injunctive relief that would limit future discharges of selenium, conductivity or sulfate through the implementation of expensive treatment technologies. The federal district court for the Southern District of West Virginia has ruled in favor of the citizen suit groups in multiple suits alleging violations of the water quality standard for selenium and in two suits alleging violations of water quality standards due to discharge of conductivity (one of which was upheld on appeal by the United States Court of Appeals for the Fourth Circuit in January 2017). Additional rulings requiring operators to reduce their discharges of selenium, conductivity or sulfate could result in large treatment expenses for mine operators.

Citizens may also sue under the Clean Water Act when pollutants are being discharged without NPDES permits. Beginning in 2013, multiple citizens’ suits were filed in West Virginia against landowners alleging ongoing discharges of pollutants, including selenium and conductivity, from valley fills at reclaimed mining sites. In each case, the reclamation bond had been released and the mining and NPDES permits had been terminated following the completion of reclamation. While it is difficult to predict the outcome of such suits, any determination that discharges from valley fills require NPDES permits could result in increased compliance costs following the completion of mining at our operations.

- Dredge and Fill Permits. Many mining activities, such as the development of refuse impoundments, fresh water impoundments, refuse fills, valley fills, and other similar structures, may result in impacts to waters of the United States, including wetlands, streams and, in certain instances, man made conveyances that have a hydrologic connection to such streams or wetlands. Under the Clean Water Act, coal companies are required to obtain a Section 404 permit from the Army Corps of Engineers, which we refer to as the Corps, prior to conducting such mining activities. The Corps is authorized to issue general “nationwide” permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse effects on the environment. Permits issued pursuant to Nationwide Permit 21, which we refer to as NWP 21, generally authorize the disposal of dredged and fill material from surface coal mining activities into waters of the United States, subject to certain restrictions. Since March 2007, permits under NWP 21 were reissued for a five year period with new provisions intended to strengthen environmental protections. There must be appropriate mitigation in accordance with nationwide general permit conditions rather than less restricted state required mitigation requirements, and permit holders must receive explicit authorization from the Corps before proceeding with proposed mining activities.

Notwithstanding the additional environmental protections designed in the NWP 21, on July 15, 2009, the Corps proposed to immediately suspend the use of NWP 21 in six Appalachian states, including West Virginia, Kentucky and Virginia where the Company conducts operations. On June 17, 2010, the Corps announced that it had suspended the use of NWP 21 in the same six states although it remained for use elsewhere. In February 2012, the Corps proposed to reissue NWP 21, albeit with significant restrictions on the acreage and length of stream channel that can be filled in the course of mining operations. The Corps' decisions regarding the use of NWP 21 does not prevent the Company's operations from seeking an individual permit under § 404 of the CWA, nor does it restrict an operation from utilizing another version of the nationwide permit, NWP 50, authorized for small underground coal mines that must construct fills as part of their mining operations.

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Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, may affect coal mining operations through its requirements for the management, handling, transportation and disposal of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. In June 2010, the EPA released a proposed rule to regulate the disposal of certain coal combustion residuals, which we refer to as CCR. The proposed rule set forth two very different options for regulating CCR under RCRA. The first option called for regulation of CCR as a hazardous waste under Subtitle C, which creates a comprehensive program of federally enforceable requirements for waste management and disposal. The second option utilized Subtitle D, which would give the EPA authority to set performance standards for waste management facilities and would be enforced primarily through citizen suits. The proposal left intact the so-called Bevill exemption for beneficial uses of CCR. The EPA finalized the CCR rule on December 19, 2014, setting nationwide solid nonhazardous waste standards for CCR disposal. On April 17, 2015, the EPA finalized regulations under the solid waste provisions (Subtitle D) of RCRA and not the hazardous waste provisions (Subtitle C) which became effective on October 19, 2015. The final rule establishes national minimum criteria for existing and new CCR landfills, surface impoundments and lateral expansions, and also establishes structural integrity criteria for new and existing surface impoundments (including establishing requirements for owners and operators to conduct periodic structural integrity-related assessments). The criteria include location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post-closure care and recordkeeping, notification and internet posting requirements. While classification of CCR as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, contamination caused by the past disposal of CCR, including coal ash, could lead to citizen suit enforcement against our customers under RCRA or other federal or state laws and potentially reduce the demand for coal. In another development regarding coal combustion wastes, the EPA conducted an assessment of impoundments and other units that manage residuals from coal combustion and that contain free liquids following a massive coal ash spill in Tennessee in 2008, the EPA contractors conducted site assessments at many impoundments and is requiring appropriate remedial action at any facility that is found to have a unit posing a risk for potential failure. The EPA is posting utility responses to the assessment on its web site as the responses are received. After industry groups filed a suit in the D.C. Circuit, challenging the 2015 rule, former EPA Administrator Pruitt issued a letter on September 13, 2017 indicating the agency’s decision to reconsider the rule in response to industry petitions. On September 27, 2017, oral arguments in the litigation were rescheduled for November 20, 2017. The court also ordered the EPA file a status report by November 15, 2017 specifying which provisions of the final rule are or are likely to be subject to reconsideration and estimated timeline for reconsideration. The court also ordered the parties to file supplemental briefs addressing the relevance to and the implications for the Water Infrastructure Improvements for the Nation Act, Pub. L. No. 114-322. Future regulations resulting from the EPA coal combustion refuse assessments may impact the ability of the Company’s utility customers to continue to use coal in their power plants.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, which we refer to as CERCLA, and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could trigger the liability provisions of the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws. In particular, we may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination at sites where we own surface rights.

Endangered Species. The Endangered Species Act and other related federal and state statutes protect species threatened or endangered with possible extinction. Protection of threatened, endangered and other special status species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species. A number of species indigenous to our properties are protected under the Endangered Species Act or other related laws or regulations. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans. We have been able to continue our operations within the existing spatial, temporal and other restrictions associated with special status species. Should more stringent protective

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measures be applied to threatened, endangered or other special status species or to their critical habitat, then we could experience increased operating costs or difficulty in obtaining future mining permits.

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. In addition, the storage of explosives is subject to strict regulatory requirements established by four different federal regulatory agencies. For example, pursuant to a rule issued by the Department of Homeland Security in 2007, facilities in possession of chemicals of interest, including ammonium nitrate at certain threshold levels, must complete a screening review in order to help determine whether there is a high level of security risk such that a security vulnerability assessment and site security plan will be required.

Other Environmental Laws. We are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act.

Employees

At December 31, 2018, we employed approximately 3,822 full and part time employees. We believe that our relations with employees are good.

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Executive Officers of the Registrant

The following is a list of our executive officers, their ages as of February 14, 2019 and their positions and offices during the last five years:

Name	Age	Position
Paul Demzik	57	Mr. Demzik has served as our Senior Vice President and Chief Commercial Officers since January 2019. From June 2013 to January 2019, Mr. Demzik served as Head of Thermal Coal Trading with Anglo American Marketing Limited in London and served as President of Peabody CoalTrade, LLC from July 2005 to July 2012.
John Drexler	49	Mr. Drexler has served as our Senior Vice President and Chief Financial Officer since 2008. Mr. Drexler served as our Vice President-Finance and Accounting from 2006 to 2008. From 2005 to 2006, Mr. Drexler served as our Director of Planning and Forecasting. Prior to 2005, Mr. Drexler held several other positions within our finance and accounting department.
John W. Eaves	61	Mr. Eaves has served as our Chief Executive Officer since 2012. Mr. Eaves served as our Chairman of the Board from 2015 to 2016 and our President and Chief Operating Officer from 2006 to 2012. From 2002 to 2006, Mr. Eaves served as our Executive Vice President and Chief Operating Officer. Mr. Eaves currently serves on the boards of the National Association of Manufacturers, the National Mining Association and CF Industries Holdings, Inc. Mr. Eaves was previously a director of Advanced Emissions Solutions, Inc. and former chairman of the National Coal Council.
Robert Jones	62	Mr. Jones has served as our Senior Vice President-Law, General Counsel and Secretary since 2008. Mr. Jones served as Vice President-Law, General Counsel and Secretary from 2000 to 2008.
Paul Lang	58	Mr. Lang was elected our President and Chief Operating Officer in April 2015. He has served as our Executive Vice President and Chief Operating Officer since April 2012 and as our Executive Vice President-Operations from August 2011 to April 2012. Mr. Lang served as Senior Vice President-Operations from 2006 through August 2011, as President of Western Operations from 2005 through 2006 and President and General Manager of Thunder Basin Coal Company from 1998 to 2005. Mr. Lang is a director of Knight Hawk Holdings, LLC. Mr. Lang also served on the development board of the Mining Department of the Missouri University of Science & Technology, and is the former chairman of the University of Wyoming’s School of Energy Resources Council.
Deck Slone	55	Mr. Slone has served as our Senior Vice President-Strategy and Public Policy since June 2012. Mr. Slone served as our Vice President-Government, Investor and Public Affairs from 2008 to June 2012. Mr. Slone served as our Vice President-Investor Relations and Public Affairs from 2001 to 2008. Mr. Slone is the Chair of the National Coal Council, the immediate past co-chair of the Carbon Utilization Research Council, and the Chair of the National Mining Association’s Energy Policy Task Force.
John A. Ziegler, Jr.	52	Mr. Ziegler was appointed Senior Vice President & Chief Administrative Officer in January 2019. Mr. Ziegler served as our Chief Commercial Officer since March 2014. Mr. Ziegler served as our Vice President-Human Resources from April 2012 to March 2014. From October 2011 to April 2012, Mr. Ziegler served as our Senior Director-Compensation and Benefits. From 2005 to October 2011 Mr. Ziegler served as Vice President-Contract Administration, President of Sales, then finally Senior Vice President, Sales and Marketing and Marketing Administration. Mr. Ziegler joined Arch Coal in 2002 as Director-Internal Audit. Prior to joining Arch Coal, Mr. Ziegler held various finance and accounting positions with bioMerieux and Ernst & Young.

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Available Information

We file annual, quarterly and current reports, and amendments to those reports, proxy statements and other information with the Securities and Exchange Commission. You may access and read our filings without charge through the SEC's website, at sec.gov.

We also make the documents listed above available without charge through our website, archcoal.com, as soon as practicable after we file or furnish them with the SEC. You may also request copies of the documents, at no cost, by telephone at (314) 994 2700 or by mail at Arch Coal, Inc., One CityPlace Drive, Suite 300, St. Louis, Missouri, 63141 Attention: Senior Vice President-Strategy and Public Policy. The information on our website is not part of this Annual Report on Form 10-K.

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GLOSSARY OF SELECTED MINING TERMS

Certain terms that we use in this document are specific to the coal mining industry and may be technical in nature. The following is a list of selected mining terms and the definitions we attribute to them.

Assigned reserves	Recoverable reserves designated for mining by a specific operation.
Bituminous coal	Coal used primarily to generate electricity and to make coke for the steel industry with a heat value ranging between 10,500 and 15,500 Btus per pound.
Btu	A measure of the energy required to raise the temperature of one pound of water one degree of Fahrenheit.
Coking coal	Coal used to produce coke, the primary source of carbon used in steelmaking.
Compliance coal	Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus, requiring no blending or other sulfur dioxide reduction technologies in order to comply with the requirements of the Clean Air Act.
Continuous miner	A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.
Dragline	A large machine used in surface mining to remove the overburden, or layers of earth and rock, covering a coal seam. The dragline has a large bucket, suspended by cables from the end of a long boom, which is able to scoop up large amounts of overburden as it is dragged across the excavation area and redeposit the overburden in another area.
Hard coal	Coal of gross calorific value greater than 5700 kcal/kg on an ashfree but moist basis and further disaggregated into anthracite, coking coal and other bituminous coal.
Lignite Coal	Coal with the lowest carbon content and a heat value ranging between 4,000 and 8,300 Btus per pound.
Longwall mining	One of two major underground coal mining methods, generally employing two rotating drums pulled mechanically back and forth across a long face of coal.
Low sulfur coal	Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.
Metallurgical coal	Coal used in steel production either as coking coal or pulverized coal injection (PCI).
Preparation plant	A facility used for crushing, sizing and washing coal to remove impurities and to prepare it for use by a particular customer.
Probable reserves	Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced.
Proven 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.
Pulverized coal injection coal (PCI)	Coal that is introduced directly into the blast furnace as a source of energy and carbon in the steelmaking process.
Reclamation	The restoration of land and environmental values to a mining site after the coal is extracted. The process commonly includes “recontouring” or shaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers.
Recoverable reserves	The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.
Reserves	That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.
Subbituminous coal	Coal used primarily to generate electricity with a heat value ranging between 8,300 and 13,000 Btus per pound.

Room and pillar mining	One of two major underground coal mining methods, utilizing continuous miners creating a network of “rooms” within a coal seam, leaving behind “pillars” of coal used to support the roof of a mine.
Unassigned reserves	Recoverable reserves that have not yet been designated for mining by a specific operation.

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ITEM 1A. RISK FACTORS.

Our business involves certain risks and uncertainties. In addition to the risks and uncertainties described below, we may face other risks and uncertainties, some of which may be unknown to us and some of which we may deem immaterial. The following review of important risk factors should not be construed as exhaustive and should be read in conjunction with other cautionary statements that are included herein or elsewhere. If one or more of these risks or uncertainties occur, our business, financial condition or results of operations may be materially and adversely affected.

Risks Related to Emergence from Bankruptcy Protection

Information contained in our historical financial statements is not comparable to the information contained in our financial statements after the application of fresh start accounting.

Following the consummation of the Plan, our financial condition and results of operations from and after the Effective Date are not comparable to the financial condition or results of operations in our historical financial statements. As a result of our restructuring under Chapter 11 of the Bankruptcy Code, our financial statements are subject to fresh start accounting provisions of generally accepted accounting principles (“GAAP”). In the application of fresh start accounting, we allocated our reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. Adjustments to the carrying amounts were material and will affect prospective results of operations as balance sheet items are settled, depreciated, amortized or impaired. This will make it difficult for stockholders to assess our performance in relation to periods prior to the Effective Date. Our Annual Report on Form 10-K for the fiscal year ended December 31, 2016 reflects the consummation of the Plan and the adoption of fresh start accounting effective October 1, 2016.

Risks Related to Our Operations

Coal prices are subject to change based on a number of factors and can be volatile. If there is a decline in prices, it could materially and adversely affect our profitability and the value of our coal reserves.

Our profitability and the value of our coal reserves depend upon the prices we receive for our coal. The contract prices we may receive in the future for coal depend upon factors beyond our control, including the following:

- the domestic and foreign supply of and demand for coal;
- the domestic and foreign demand for electricity and steel;
- the quantity and quality of coal available from competitors;
- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels;
- domestic and foreign air emission standards for coal-fueled power plants and the ability of coal-fueled power plants to meet these standards;
- adverse weather, climatic or other natural conditions, including unseasonable weather patterns;
- domestic and foreign economic conditions, including economic slowdowns and the exchange rate of U.S. dollars for foreign currency;
- domestic and foreign legislative, regulatory and judicial developments, environmental regulatory changes or changes in energy policy and energy conservation measures that would adversely affect the coal industry, such as legislation limiting carbon emissions or providing for increased funding and incentives for alternative energy sources;
- the imposition of tariffs, quotas, trade barriers and other trade protection measures;
- the proximity to, capacity of and cost of transportation and port facilities;
- market price fluctuations for sulfur dioxide or nitric oxide emission allowances; and
- technological advancements, 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.

Declines in the prices we receive for our future coal sales contracts, could materially and adversely affect us by decreasing our profitability, cash flows, liquidity and the value of our coal reserves.

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Unfavorable economic and market conditions have adversely affected and may continue to affect our revenues and profitability.

Our profitability depends, in large part, on conditions in the markets that we serve, which fluctuate in response to various factors beyond our control. The prices at which we sell our coal are largely dependent on prevailing market prices. We have experienced significant price pressure at times during the past several years as the demand for, and price of, coal has been subject to pressure for a variety of reasons, including reductions in domestic and international demand for metallurgical and thermal coal.

Global economic downturns have also had and in the future could have a negative impact on us. These conditions have, in the past, led to extreme volatility of prices, severely limited liquidity and credit availability, and resulted in declining valuations of assets. If there are downturns in economic conditions, our and our customers' businesses, financial conditions and results of operations could be adversely affected. Furthermore, because we typically seek to enter into long-term arrangements for the sale of a substantial portion of our coal, the average sales price we receive for our coal may lag behind any general economic recovery. There can be no assurance that our cost control actions and capital discipline, or any other actions that we may take, will be sufficient to offset any adverse effect these conditions may have on our business, financial condition or results of operations.

The effects of foreign and domestic trade policies, actions or disputes on the level of trade among the countries and regions in which we operate could negatively impact our business, financial condition or results of operations.

Tariffs imposed by the current presidential administration could potentially lead to trade disputes with other foreign governments and adversely impact global economic conditions. For instance, in March 2018, the current administration imposed a 25% tariff on all imported steel into the United States which could negatively impact the global demand for steel, and in turn, the demand for metallurgical coal. While the new steel tariffs appear to have had little impact on coking coal pricing or demand to date, longer term implications for coking coal markets and the global economy as a whole remain less certain. In addition, continued or worsening U.S.-China trade tensions may result in additional tariffs or other protectionist measures that materially, adversely affect foreign demand for our coal.

Competition could put downward pressure on coal prices and, as a result, materially and adversely affect our revenues and profitability.

We compete with numerous other domestic and foreign coal producers for domestic and international sales. Overcapacity and increased production within the coal industry, both domestically and internationally, and decelerating steel demand in Asia have at times, and could in the future, materially reduce coal prices and therefore materially reduce our revenues and profitability. Potential changes to international trade agreements, trade policies, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We may not be able to compete on the basis of price or other factors with companies that in the future benefit from favorable foreign trade policies or other arrangements. In addition, our ability to ship our coal to international customers depends on port capacity, which is limited. Increased competition within the coal industry for international sales could result in us not being able to obtain throughput capacity at port facilities, or the rates for such throughput capacity increasing to a point where it is not economically feasible to export our coal.

The domestic coal industry has experienced consolidation in recent years, including consolidation among some of our major competitors. In addition, substantial overcapacity exists in the coal industry and several other large coal companies have also filed, and others may file, bankruptcy proceedings which could enable them to lower their productions costs and thereby reduce the price for coal. Consolidation in the coal industry or current or future bankruptcy proceedings of our coal competitors could adversely affect our competitive position.

In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas. Natural gas pricing has declined significantly in recent years. The decline in the price of natural gas has caused demand for coal to decrease and adversely affected the price of our coal. Sustained periods of low natural gas prices have also contributed to utilities phasing out or closing existing coal-fired power plants and continued low prices could reduce or eliminate construction of any new coal-fired power plants. This trend has, and could continue to have, a material adverse effect on demand and prices for our coal. Moreover, the construction of new pipelines and other natural gas distribution channels may increase competition within regional markets and thereby decrease the demand for and price of our coal.

Furthermore, several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reduction in the amount of coal consumed by electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Any decrease in the coal consumption of electric power generators could result in less demand and lower prices for coal, which could materially and adversely affect our revenues and results of operations.

Thermal coal accounted for 92% of our coal sales by volume during 2018. The majority of these sales were to electric power generators. The amount of coal consumed for electric power generation is affected primarily by the overall demand for electricity, the availability, quality and price of competing fuels (particularly natural gas) for power generation and governmental regulations which may dictate an alternate source of fuel regardless of economics. Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand and can be impacted by a number of factors. An economic slowdown can significantly slow the growth of electricity demand and could result in reduced demand for coal. For example, declines in the rate of international economic growth in countries such as China, India or other developing countries could further negatively impact the demand for U.S. coal and result in a continuing oversupply of coal in the marketplace. Weather patterns can also greatly affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increase generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand, which allow generators to choose the source of power generation when deciding which generation source to dispatch.

Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators and this has occurred to date. We expect that many of the new power plants constructed in the United States to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain as natural gas combustion is seen as having a lower environmental impact than coal combustion. In addition, state and federal mandates for increased use of electricity from renewable energy sources also have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform national standard, although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reduction in the amount of coal consumed by electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Our coal mining operations are subject to operating risks that are beyond our control, which could result in materially increased operating expenses and decreased production levels and could materially and adversely affect our profitability.

We mine coal at underground and surface mining operations. Certain factors beyond our control, including those listed below, could disrupt our coal mining operations, adversely affect production and shipments and increase our operating costs:

- poor mining conditions resulting from geological, hydrologic or other conditions that may cause instability of highwalls or spoil piles or cause damage to nearby infrastructure or mine personnel;
- a major incident at the mine site that causes all or part of the operations of the mine to cease for some period of time;
- mining, processing and plant equipment failures and unexpected maintenance problems;
- adverse weather and natural disasters, such as heavy rains or snow, flooding and other natural events affecting operations, transportation or customers;
- the unavailability of raw materials, equipment (including heavy mobile equipment) or other critical supplies such as tires, explosives, fuel, lubricants and other consumables of the type, quantity and/or size needed to meet production expectations;
- unexpected or accidental surface subsidence from underground mining;

- accidental mine water discharges, fires, explosions or similar mining accidents;
- delays or closures by third-party transportation on coal shipments; and
- competition and/or conflicts with other natural resource extraction activities and production within our operating areas, such as coalbed methane extraction or oil and gas development.

If any of these conditions or events occurs, particularly at our Black Thunder or Leer mining complexes, which accounted for approximately 77% of the coal volume we sold and 57% of the revenue we generated in 2018, our coal mining operations may be disrupted and we could experience a delay or halt of production or shipments or our operating costs could

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increase significantly. In addition, if our insurance coverage is limited or excludes certain of these conditions or events, then we may not be able to recover any of the losses we may incur as a result of such conditions or events, some of which may be substantial.

A decline in demand for metallurgical coal would limit our ability to sell our coal into higher-priced metallurgical markets and could substantially affect our business.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the metallurgical and steam coal markets. We decide whether to mine, process and market these coals as metallurgical or steam coal based on management's assessment as to which market is likely to provide us with a higher margin. We consider a number of factors when making this assessment, including the difference between the current and anticipated future market prices of steam coal and metallurgical coal and the increased costs incurred in producing coal for sale in the metallurgical market instead of the steam market. A decline in prices in the metallurgical market relative to the steam market could cause us, as well as our competitors, to shift coal from the metallurgical market to the steam market, thereby reducing our revenues and profitability and increasing the availability of coal to customers in the steam market.

Our inability to acquire additional coal reserves or our inability to develop coal reserves in an economically feasible manner may adversely affect our business.

Our profitability depends substantially on our ability to mine and process, in a cost-effective manner, coal reserves that possess the quality characteristics desired by our customers. As we mine, our coal reserves decline. As a result, our future success depends upon our ability to obtain, through acquisition or redevelopment of owned reserves, coal that is economically recoverable. If we fail to acquire or develop additional coal reserves, our existing reserves will eventually be depleted. We may not be able to obtain replacement reserves when we require them. If available, replacement reserves may not be available at favorable prices, or we may not be capable of mining those reserves at costs that are comparable with our existing coal reserves. 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.

Our ability to obtain coal reserves in the future could also be limited by the availability of cash we generate from our operations or available financing, restrictions under our existing or future financing arrangements, competition from other coal producers, the lack of suitable acquisition or lease-by-application, ("LBA"), opportunities or the inability to acquire coal properties or LBAs on commercially reasonable terms. Increased opposition from non-governmental organizations and other third parties may also lengthen, delay or adversely impact the LBA process. If we are unable to acquire replacement reserves, our future production may decrease significantly and our operating results may be negatively affected. In addition, we may not be able to mine future reserves as profitably as we do at our current operations.

In January 2016, the federal government imposed a moratorium on new leases for coal mined from federal lands as part of a review of the government's management of federally-owned coal. In March 2017, the U.S. Secretary of the Interior signed Secretarial Order 3348 lifting that moratorium and halting the Federal Coal Program Programmatic Environmental Impact Statement that was in process at the time. Litigation is currently pending in the United States District Court for the District of Montana challenging the lifting of the moratorium as a violation of the National Environmental Policy Act, the Mineral Leasing Act and the Federal Land Policy and Management Act. Although the Bureau of Land Management is now working to process coal lease applications and modifications expeditiously in accordance with regulations and guidance that existed before the moratorium, any delay in the LBA process, including any delay caused by the reimplementation of the now-lifted moratorium could prevent us from obtaining replacement reserves when we require them. Also, the outcome of the government's review, if re-initiated, would be uncertain and could have a material and adverse impact on our business in any number of ways including by limiting our ability to mine reserves under ongoing or future applications, by increasing the costs or timeframe associated with obtaining leases under the LBA program, by making it uneconomical for us to participate in the programs or by preventing us from obtaining replacement reserves if the LBA program were terminated.

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Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs.

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. We base our estimates of reserves on engineering, economic and geological data assembled, analyzed and reviewed by internal and third-party engineers and consultants. We update our estimates of the quantity and quality of proven and probable coal reserves annually to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;
- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;
- the percentage of coal ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- assumptions concerning the timing for the development of the reserves;
- assumptions concerning physical access to the reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy in our estimates related to our reserves could result in decreased profitability from lower than expected revenues and/or higher than expected costs.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal which could have a material adverse effect on our business and results of operations.

Federal and state laws require us to obtain surety bonds or post letters of credit to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other obligations. The costs of surety bonds have fluctuated in recent years while the market terms of such bonds have generally become less favorable to mine operators. These changes in the terms of the bonds have been accompanied at times by a decrease in the number of companies willing to issue surety bonds. In addition, federal and state regulators are considering making financial assurance requirements with respect to mine closure and reclamation more stringent. Because we are required by federal and state law to have these bonds in place before mining can commence or continue, our failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal.

Increases in the costs of mining and other industrial supplies, including steel-based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production.

Our coal mining operations use significant amounts of steel, diesel fuel, explosives, rubber tires and other mining and industrial supplies. The cost of roof bolts we use in our underground mining operations depends on the price of scrap steel. We also use significant amounts of diesel fuel and tires for trucks and other heavy machinery, particularly at our Black Thunder mining complex. 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. If the prices of mining and other industrial supplies, particularly steel based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected. In addition, if we are unable to procure these supplies, our coal mining operations may be disrupted or we could experience a delay or halt in our production.

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Our profitability depends upon the coal supply agreements we have with our customers. Changes in purchasing patterns in the coal industry could make it difficult for us to extend our existing coal supply agreements or to enter into new agreements in the future.

The success of our businesses depends on our ability to retain our current customers, renew our existing customer contracts and solicit new customers. Our ability to do so generally depends on a variety of factors, including the quality and price of our products, our ability to market these products effectively, our ability to deliver on a timely basis and the level of competition that we face. If current customers do not honor current contract commitments, or if they terminate agreements or exercise force majeure provisions allowing for the temporary suspension of performance, our revenues will be adversely affected. Changes in the coal industry may cause some of our customers not to renew, extend or enter into new coal supply agreements or to enter into agreements to purchase fewer tons of coal or on different terms or prices than in the past. In addition, uncertainty caused by federal and state regulations, including under the U.S. Clean Air Act, could deter our customers from entering into coal supply agreements. Also, the availability and price of competing fuels, such as natural gas, could influence the volume of coal a customer is willing to purchase under contract.

Our coal supply agreements typically contain force majeure provisions allowing the parties to temporarily suspend performance during specified events beyond their control. Most of our coal supply agreements also contain provisions requiring us to deliver coal that satisfies certain quality specifications, such as heat value, sulfur content, ash content, hardness and ash fusion temperature. These provisions in our coal supply agreements could result in negative economic consequences to us, including price adjustments, having to purchase replacement coal in a higher-priced open market, the rejection of deliveries or, in the extreme, contract termination. Our profitability may be negatively affected if we are unable to seek protection during adverse economic conditions or if we incur financial or other economic penalties as a result of these provisions of our coal supply agreements. For more information about our long-term coal supply agreements, you should see the section entitled “Long-Term Coal Supply Arrangements” under Item 1.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates and our financial position could be materially and adversely affected by the bankruptcy of any of our significant customers.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If we determine that a customer is not creditworthy, we may be able to withhold delivery under the customer’s coal sales contract. If this occurs, we may decide to sell the customer’s coal on the spot market, which may be at prices lower than the contracted price, or we may be unable to sell the coal at all. Furthermore, the bankruptcy of any of our significant customers could materially and adversely affect our financial position.

In addition, our customer base may change with deregulation as utilities sell their power plants to their non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear for customer payment default. Some power plant owners may have credit ratings that are below investment grade, or may become below investment grade after we enter into contracts with them. In addition, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk of payment default. Customers in other countries may also be subject to other pressures and uncertainties that may affect their ability to pay, including trade barriers, exchange controls and local economic and political conditions.

A defect in title or the loss of a leasehold interest in certain property or surface rights could limit our ability to mine our coal reserves or result in significant unanticipated costs.

We conduct a significant part of our coal mining operations on properties that we lease. A title defect or the loss of a lease or surface rights could adversely affect our ability to mine the associated coal reserves. We may not verify title to our leased properties or associated coal reserves until we have committed to developing those properties or coal reserves. We may not commit to develop property or coal reserves until we have obtained necessary permits and completed exploration. As such, the title to property that we intend to lease or coal reserves that we intend to mine may contain defects prohibiting our ability to conduct mining operations. Similarly, our leasehold interests may be subject to superior property rights of other third parties. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, some leases require us to produce a minimum quantity of coal and require us to pay minimum production royalties. Our inability to satisfy those requirements may cause the leasehold interest to terminate.

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The availability, reliability and cost-effectiveness of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers.

We depend upon barge, ship, rail, truck and belt transportation systems, as well as seaborne vessels and port facilities, to deliver coal to our customers. Disruptions in transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, route closures and other events beyond our control could impair our ability to supply coal to our customers. Since we do not have long-term contracts with all transportation providers we utilize, decreased performance levels over longer periods of time could cause our customers to look to other sources for their coal needs. In addition, increases in transportation costs, including the price of gasoline and diesel fuel, could make coal a less competitive source of energy when compared to alternative fuels or could make coal produced in one region of the United States less competitive than coal produced in other regions of the United States or abroad. If we experience disruptions in our transportation services or if transportation costs increase significantly and we are unable to find alternative transportation providers, our coal mining operations may be disrupted, we could experience a delay or halt of production or our profitability could decrease significantly. In addition, a growing portion of our coal sales in recent years has been into export markets, and we are actively seeking additional international customers. Our ability to maintain and grow our export sales revenue and margins depends on a number of factors, including the existence of sufficient and cost-effective export terminal capacity for the shipment of coal to foreign markets. At present, there is limited terminal capacity for the export of coal into foreign markets. Our access to existing and future terminal capacity may be adversely affected by, among other factors, regulatory and permit requirements, environmental and other legal challenges, public perceptions and resulting political pressures, foreign and domestic trade policies, operational issues at terminals and competition among domestic coal producers for access to limited terminal capacity. If we are unable to maintain terminal capacity, or are unable to access additional future terminal capacity for the export of our coal on commercially reasonable terms, or at all, our results could be materially and adversely affected.

From time to time we enter into “take or pay” contracts for rail and port capacity related to our export sales. These contracts require us to pay for a minimum quantity of coal to be transported on the railway or through the port regardless of whether we sell and ship any coal. If we fail to acquire sufficient export sales to meet our minimum obligations under these contracts, we are still obligated to make payments to the railway or port facility, which could have a negative impact on our cash flows, profitability and results of operations.

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

For the year ended December 31, 2018, we derived approximately 20% of our total coal revenues from sales to our three largest customers and approximately 41% of our total coal revenues from sales to our ten largest customers. We are currently discussing the extension of coal sales agreements with some of these customers. However, we may be unsuccessful in obtaining coal supply agreements with those customers, and some or all of these customers could discontinue purchasing coal from us. If any of those customers, particularly any of our three largest customers, were to significantly reduce the quantities of coal it purchases from us, or if we are unable to sell coal to those customers on terms as favorable to us, it may have an adverse impact on the results of our business.

We may incur losses as a result of certain marketing, trading and asset optimization strategies.

We seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of marketing, trading and other asset optimization strategies. We maintain a system of complementary processes and controls designed to monitor and control our exposure to market and other risks as a consequence of these strategies. These processes and controls seek to balance our ability to profit from certain marketing, trading and asset optimization strategies with our exposure to potential losses. Our risk monitoring and mitigation techniques, and accompanying judgments cannot anticipate every potential outcome or the timing of such outcomes. In addition, the processes and controls that we use to manage our exposure to market and other risks resulting from these strategies involve assumptions about the degrees of correlation or lack thereof among prices of various assets or other market indicators. These correlations may change significantly in times of market turbulence or other unforeseen circumstances. As a result, we may experience volatility in our earnings as a result of our marketing, trading and asset optimization strategies.

International growth in our operations adds new and unique risks to our business.

We have sales offices in Singapore and the United Kingdom. The international expansion of our operations increases our exposure to country and currency risks. In addition, our international offices sell our coal to new customers and customers in new countries, whose business practices and reputations are not as well known to us. We also face new and increased political risks, including the potential for expropriation of assets and limitations on the repatriation of earnings. In the event that we are unable to effectively manage these new risks, our results of operations, financial position or cash flow could be adversely affected by these activities.

If we sustain cyber-attacks or other security breaches that disrupt our operations, or that result in the unauthorized release of proprietary or confidential information, we could be exposed to significant liability, reputational harm, loss of revenue, increased costs or other risks.

We have become increasingly dependent on information technology systems to operate our business and to comply with regulatory, legal and tax requirements. As our dependence on digital technologies has increased, the risk of cyber incidents, including both deliberate attacks and unintentional events, also has increased. A cyber-attack may involve persons gaining unauthorized access to our digital systems for purposes of gathering, monitoring, releasing, misappropriating or corrupting proprietary or confidential information, or causing operational disruption. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Strategic targets, such as energy-related assets, may be at greater risk of future cyber-attacks than other targets in the United States.

To date, we have not experienced any material losses relating to cyber incidents. However, our systems may be susceptible to cyber incidents or security breaches which could result in unauthorized access to our facilities or to information we are trying to protect. Failure of our systems, whether caused maliciously or inadvertently, may lead to unauthorized physical access to one or more of our facilities or locations, or electronic access to our proprietary or confidential information and could result in, among other things, unfavorable publicity, litigation by parties affected by such breach, disruptions to our operations, loss of customers and financial obligations that may not be covered by our insurance for damages, fines or penalties related to the theft, release or misuse of such information, any of which could have a substantial impact on our results of operations, financial condition or cash flow. As cyber threats continue to evolve, we may be required to expend significant additional resources to modify or enhance our protective measures or to investigate and remediate any system vulnerabilities.

Our ability to operate our business 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. Failure to retain or attract key personnel could have a material adverse effect on us.

We may be unable to comply with the restrictions imposed by our Term Loan Debt Facility and other financing arrangements.

The agreements governing our outstanding financing arrangements impose a number of restrictions on us. For example, the terms of our credit facilities, leases and other financing arrangements contain financial and other covenants that may create limitations on our ability to borrow the full amount under our credit facilities, effect acquisitions or dispositions and incur additional debt and require us to comply with various affirmative covenants. The Term Loan Debt Facility contains customary affirmative and negative covenants, which include restrictions on (i) indebtedness, (ii) liens, (iii) liquidations, mergers, consolidations and acquisitions, (iv) disposition of assets or subsidiaries, (v) affiliate transactions, (vi) creation or ownership of certain subsidiaries, partnerships and joint ventures, (vii) continuation of or change in business, (viii) restricted payments, (ix) prepayment of subordinated and junior lien indebtedness, (x) restrictions in agreements on dividends, intercompany loans and granting liens on the collateral, (xi) loans and investments, (xii) sale and leaseback transactions, (xiii) changes in organizational documents and fiscal year and (xiv) transactions with respect to bonding subsidiaries. Our ability to comply with these provisions may be affected by events beyond our control and our failure to comply could result in an event of default under the Term Loan Debt Facility.

We may not be able to pay dividends or repurchase shares of our common stock in accordance with our announced intent or at all.

The Board of Directors’ determinations regarding dividends and share repurchases will depend on a variety of factors, including our net income, cash flow generated from operations or other sources, liquidity position and potential alternative uses of cash, such as acquisitions and organic growth opportunities, as well as economic conditions and expected future financial results.

Our ability to declare future dividends and make future share repurchases 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 and selling prices for our products and other factors specific

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to our industry, many of which are beyond our control. Therefore, our ability to generate cash depends on the performance of our operations and could be limited by decreases in our profitability or increases in costs, regulatory changes, capital expenditures or debt servicing requirements.

Any failure to pay dividends or repurchase shares of our common stock could negatively impact our reputation, lessen investor confidence in us, and cause the market price of our common stock to decline.

Risks Related to Environmental, Other Regulations and Legislation

Extensive environmental regulations, including existing and potential future regulatory requirements relating to air emissions, affect our customers and could reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline.

Coal contains impurities, including but not limited to sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, the federal Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxide, and other compounds emitted into the air from electric power plants, which are the largest end users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, sulfur dioxide, nitrogen oxide and other air pollutants may be developed and implemented. For instance, the Clean Power Plan, if implemented in the form promulgated under the Obama Administration, would severely limit emissions of carbon dioxide which would adversely affect our ability to sell coal. However, in April 2017, the EPA announced that it was initiating a review of the Clean Power Plan consistent with President Trump’s Executive Order 13783, and, in October 2017, the EPA published a proposed rule to formally repeal the Clean Power Plan. On August 21, 2018, the EPA proposed the Affordable Clean Energy rule which revises the agency’s interpretation of Clean Air Act section 111(d). The proposed rule offers the power generation industry incentives to invest in coal-fired power plants and provides guidelines for reducing carbon dioxide emissions by making on-site “heat rate improvements.” It also eliminates the Obama-era requirement to limit emissions of pollutants other than carbon dioxide. The comment period for the rule closed October 30, 2018. Any final rule promulgated by the EPA will likely be subject to judicial review, and, as such, the future of the Clean Power Plan and its attendant regulations is unclear. In December 2015, the United States and 195 other countries reached an agreement (the “Paris Agreement” during the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change, a long-term, international framework convention designed to address climate change over the next several decades. In August 2017, the Trump Administration filed formal notice with the United Nations that the United States plans to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or to establish a new framework agreement. The earliest permitted exit date under the Paris Agreement is four years from when the agreement took effect in November 2016, or November 2020. Whether the United States will adhere to the Paris Agreement’s exit process is, and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are, uncertain at this time. However, any efforts to control and/or reduce greenhouse gas emissions by the United States or other countries that have also pledged “Nationally Determined Contributions,” or concerted conservation efforts that result in reduced electricity consumption, could adversely impact coal prices, our ability to sell coal and, in turn, our financial position and results of operations.

We are also subject to state and local regulations, which may be more stringent than federal rules. For example, although the United States has announced its intention to withdraw from the Paris Agreement, certain United States cities and states have announced their intention to satisfy their proportionate obligations under the Paris Agreement. In addition, almost one-half of states have taken measures to track and reduce emissions of greenhouse gases, and some states have elected to participate in voluntary regional cap-and-trade programs like the Regional Greenhouse Gas Initiative in the northeastern United States. State and local governments may pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may decrease demand for our coal products. State and local commitments and regulations could have a material adverse effect on our business, financial condition and results of operations.

Considerable uncertainty is associated with these air emissions initiatives, and the content of regulatory requirements in the United States and other countries continues to evolve and develop, which could require significant emissions control expenditures for many coal fueled power plants. As a result, these power plants may switch to other fuels that generate fewer of these emissions, may install more effective pollution control equipment that reduces the need for low sulfur coal, or may cease operations, possibly reducing future demand for coal and a reduced need to construct new coal fueled power plants. Any switching of fuel sources away from coal, closure of existing coal fired plants or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal. Alternatively, less stringent air emissions limitations, particularly related to sulfur, to the extent enacted, could make low sulfur coal less attractive, which could also have a material adverse effect on the demand for and prices received for our coal.

You should see Item 1, “Environmental and Other Regulatory Matters” for more information about the various governmental regulations affecting the market for our products.

The demand for our products or our securities, as well as the number and quantity of viable financing alternatives, may be significantly impacted by increased governmental regulations and unfavorable lending and investment policies by financial institutions and insurance companies associated with concerns about environmental impacts of coal combustion, including perceived impacts on the global climate.

Carbon dioxide, which is considered to be a greenhouse gas, is a by-product of burning coal. Global climate issues, including with respect to greenhouse gases such as carbon dioxide and the relationship that greenhouse gases may have with perceived climate change, continue to attract significant public and scientific attention. For example, the Fourth and Fifth Assessment Reports of the Intergovernmental Panel on Climate Change have expressed concern about the impacts of human activity, especially from fossil fuel combustion, on the global climate. As a result of the public and scientific attention, several governmental bodies increasingly are focusing on climate issues and, more specifically, levels of emissions of carbon dioxide from coal combustion by power plants. The Clean Power Plan would severely limit emissions of carbon dioxide, possibly reducing future demand for coal. However, in April 2017 the EPA announced that it was initiating a review of the Clean Power Plan consistent with President Trump’s Executive Order 13783, and in August 2018 proposed the Affordable Clean Energy rule to formally repeal the Clean Power Plan. Any final rule promulgated by the EPA will likely be subject to judicial review, and as such, the future of the Clean Power Plan and its attendant regulations is unclear. Additionally, a number of governments pledged to control and reduce greenhouse gas emissions under the Paris Agreement, which may impact demand for coal resources despite the United States’ August 2017 notice that it intends to withdraw its commitment.

Future regulation of greenhouse gas emissions in the United States could occur pursuant to future treaty obligations, statutory or regulatory changes at the federal, state or local level or otherwise. The enactment of laws or the passage of regulations regarding greenhouse gas emissions from the combustion of coal by the U.S., some of its states or other countries, or other actions to limit emissions could result in electricity generators switching from coal to other fuel sources or coal-fueled power plant closures. You should see Item 1, “Environmental and Other Regulatory Matters-Climate Change” for more information about governmental regulations relating to greenhouse gas emissions.

In addition, several major 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 mines and utilities that derive a majority of their revenue from thermal coal, which also may adversely impact the future global demand for coal. Further, there have been recent efforts by members of the general financial and investment communities, such as investment advisors, sovereign wealth funds, public pension funds, universities and other groups, to divest themselves and to promote the divestment of securities issued by companies involved in the fossil fuel extraction market, such as coal producers. For example, California enacted legislation that required California’s state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining. These entities also have been pressuring lenders to limit financing available to such companies. These efforts may adversely affect the market for our securities and our ability to access capital and financial markets in the future.

Any future laws, regulations or other policies of the nature described above may adversely impact our business in material ways. The degree to which any particular law, regulation or policy impacts us will depend on several factors, including the substantive terms involved, the relevant time periods for enactment and any related transition periods. We routinely attempt to evaluate the potential impact on us of any proposed laws, regulations or policies, which requires that we make several material assumptions. From time to time, we determine that the impact of one or more such laws, regulations or policies, if adopted and ultimately implemented as proposed, may result in materially adverse impacts on our operations, financial condition or cash flow. In general, it is likely that any future laws, regulations or other policies aimed at reducing greenhouse gas emissions will negatively impact demand for our coal.

Our failure to obtain and renew permits necessary for our mining operations could negatively affect our business.

Mining companies must obtain numerous permits that impose strict regulations on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. The permitting rules, and the interpretations of these rules, are complex, change frequently and are often subject to discretionary interpretations by the regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing operations or the development of future mining operations. The public,

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including non governmental organizations, anti mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, 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. Accordingly, required permits may not be issued or renewed in a timely fashion or at all, or permits issued or renewed may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow and profitability.

Federal or state regulatory agencies have the authority to order certain of our mines to be temporarily or permanently closed under certain circumstances, which could materially and adversely affect our ability to meet our customers' demands.

Federal or state regulatory agencies have the authority, under certain circumstances following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this occurred, we may be required to incur capital expenditures to re open the mine. In the event that these agencies order the closing of our mines, our coal sales contracts generally permit us to issue force majeure notices which suspend our obligations to deliver coal under these contracts. However, our customers may challenge our issuances of force majeure notices. If these challenges are successful, we may have to purchase coal from third party sources, if it is available, to fulfill these obligations, incur capital expenditures to re open the mines and/or negotiate settlements with the customers, which may include price reductions, the reduction of commitments, the extension of time for delivery or the termination of customers' contracts. Any of these actions could have a material adverse effect on our business and results of operations.

Extensive environmental regulations impose significant costs on our mining operations, and future regulations could materially increase those costs or limit our ability to produce and sell coal.

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

- limitations on land use;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed and required surety bonds or other instruments to secure those reclamation and restoration obligations;
- management of materials generated by mining operations;
- the storage, treatment and disposal of wastes;
- remediation of contaminated soil and groundwater;
- air quality standards;
- water pollution;
- protection of human health, plant life and wildlife, including endangered or threatened species;
- protection of wetlands;
- the discharge of materials into the environment;
- the effects of mining on surface water and groundwater quality and availability; and
- the management of electrical equipment containing polychlorinated biphenyls.

The costs, liabilities and requirements associated with the laws and regulations related to these and other environmental matters may be costly and time consuming and may delay commencement or continuation of exploration or production operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may incur material costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. If we are pursued for sanctions, costs and liabilities in respect of these matters, our mining operations and, as a result, our profitability could be materially and adversely affected.

New legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations, including proposals related to the protection of the environment that would further regulate and tax the coal industry, may also require us to change operations significantly or incur increased costs. Please refer to the section entitled "Environmental and Other Regulatory Matters" in Item 1 for more information about the various governmental regulations affecting us.

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If the assumptions underlying our estimates of reclamation and mine closure obligations are inaccurate, our costs could be greater than anticipated.

SMCRA and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of underground mining. We base our estimates of reclamation and mine closure liabilities on permit requirements, engineering studies and our engineering expertise related to these requirements. Our management and engineers periodically review these estimates. The estimates can change significantly if actual costs vary from our original assumptions, major operational changes are implemented or if governmental regulations change significantly. We are required to record new obligations as liabilities at fair value under U.S. GAAP. In estimating fair value, we considered the estimated current costs of reclamation and mine closure and applied inflation rates and a third party profit, as required. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The resulting estimated reclamation and mine closure obligations 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 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. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and cleanup of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or at sites that we may acquire. Under certain federal and state environmental laws, our liability for such conditions may be joint and several with other owners/operators, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share. Liability under these laws is generally strict. Accordingly, we may incur liability without regard to fault or to the legality of the conduct giving rise to the conditions.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Slurry impoundments can fail, which could release large volumes of coal slurry into the surrounding environment. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined-out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as “acid mine drainage,” which we refer to as AMD. The treating of AMD can be costly. Although we do not currently face material costs associated with AMD, it is possible that we could incur significant costs in the future.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us.

Judicial rulings that restrict how we may dispose of mining wastes could significantly increase our operating costs, discourage customers from purchasing our coal and materially harm our financial condition and operating results.

To dispose of mining overburden generated by our Appalachian surface mining operations, we often need to obtain permits to construct and operate valley fills and surface impoundments. Some of these permits are Clean Water Act § 404 permits issued by the Army Corps of Engineers (the “Corps”). Two of our operating subsidiaries were identified in an existing lawsuit, which challenged the issuance of such permits and asked that the Corps be ordered to rescind them. Two of our operating subsidiaries intervened in the suit to protect their interests in being allowed to operate under the issued permits, and the claims against one of our subsidiaries was thereafter dismissed. On February 13, 2009, the U.S. Court of Appeals for the Fourth Circuit ruled on appeals from decisions rendered prior to our intervention. On May 22, 2017, the United States District Court for the Southern District of West Virginia granted the remaining subsidiary's motion to dismiss plaintiffs' Seventh Supplemental and Amended Complaint after the D.C. Circuit Court of Appeals affirmed the EPA's final determination rescinding Mingo Logan Coal Company's 404 authorization regarding Pigeonroost Branch and Oldhouse Branch. The D.C. Circuit Court of Appeals decision finally resolved a lawsuit filed by Mingo Logan against the EPA challenging the EPA's authority to rescind a 404 permit authorization.

Changes in the legal and regulatory environment could complicate or limit our business activities, increase our operating costs or result in litigation.

The conduct of our businesses is subject to various laws and regulations administered by federal, state and local governmental agencies in the United States. These laws and regulations may change, sometimes dramatically, as a result of political, economic or social events or in response to significant events. Environmental and other non-governmental organizations and activists, many of which are well funded, continue to exert pressure on regulators and other government bodies to enact more stringent laws and regulations. For instance, increasing attention to global climate change has resulted in an increased possibility of governmental investigations and, potentially, private litigation against us and our customers. For example, claims have been made against certain energy companies alleging that greenhouse gas emissions constitute a public nuisance. While our business is not a party to any such litigation, we could be named in actions making similar allegations. Moreover, the proliferation of successful climate change litigation could adversely impact demand for coal and ultimately have a material adverse effect on our business, financial condition and results of operations. Changes in the legal and regulatory environment in which we operate may impact our results, increase our costs or liabilities, complicate or limit our business activities or result in litigation. Such legal and regulatory environment changes may include changes in such items as: the processes for obtaining or renewing permits; federal LBA programs; costs associated with providing healthcare benefits to employees; health and safety standards; accounting standards; taxation requirements; competition laws; and trade policies, including policies concerning tariffs, quotas, trade barriers and other trade protection measures.

We or our customers could be subject to litigation based on the alleged effects of climate change.

Increasing attention to global climate change has resulted in an increased possibility of governmental investigations and, potentially, private litigation against us and our customers. For example, claims have been made against certain energy companies alleging that greenhouse gas emissions constitute a public nuisance. While the United States Supreme Court held that federal common law provides no basis for public nuisance claims against energy companies, state law tort claims remain a possibility and a source of concern, and we could be named in actions making similar allegations. Moreover, the proliferation of successful climate change litigation could adversely impact demand for coal and ultimately have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Income Taxes

Our ability to use net operating losses and alternative minimum tax credits is subject to limitation.

The ability to use our net operating losses (“NOLs”) and alternative minimum tax (“AMT”) credits has been limited by the “ownership change” under Section 382 of the Internal Revenue Code (the “Code”) that occurred on our emergence from bankruptcy in 2016 (the “Emergence Ownership Change”). The limitation resulting from the Emergence Ownership Change is substantial and applies to all NOLs and AMT credits existing at the time of the Emergence Ownership Change. The limitation resulting from the Emergence Ownership Change may have a significant impact on our ability to offset future taxable income with carryforward NOLs. NOLs and AMT credits generated after the Emergence Ownership Change are generally not subject to the limitations.

As a result of the discharge of debt in the Chapter 11 Cases, we and our subsidiaries were required to reduce the amount of our NOLs and AMT credits and other tax attributes existing at the end of 2016.

Recent U.S. tax legislation may materially adversely affect our financial condition, results of operations and cash flows.

U.S. tax legislation enacted on December 22, 2017 (the “Tax Cut and Jobs Act”) has significantly changed the U.S. federal income taxation of U.S. corporations. Changes include the reduction of the U.S. corporate income tax rate, elimination of the AMT tax system, limitation of interest deductions and revision of the rules governing NOLs.

As a result of the Tax Cuts and Jobs Act, there was a remeasurement of our deferred tax assets and liabilities, which resulted in $330.9 million of income tax expense in 2017 and $16.7 million of income tax benefit in 2018, with offsetting valuation allowance adjustments. In addition, we incurred a one-time transition tax of $1.5 million on the mandatory deemed repatriation of cumulative foreign earnings, which deemed repatriation tax was offset with NOL carryforwards (with an offsetting valuation allowance adjustment). Due to the elimination of the corporate AMT regime, existing AMT credits as of December 31, 2018 will be refunded during 2019-2022, and therefore the valuation allowance previously recorded against these credits has been released and the credits have been reclassified from a deferred tax asset to short term and long term receivables. As a result of limitations imposed by the Tax Cuts and Jobs Act on deductible compensation paid to certain

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“covered” employees, we recorded $0.2 million of tax expense in 2017 and $6.1 million of tax expense in 2018, with offsetting valuation allowance adjustments.

The Tax Cut and Jobs Act is subject to potential amendments and technical corrections, as well as interpretations and implementing regulations by the Treasury Department and Internal Revenue Service (“IRS”), any of which could lessen or increase certain adverse impacts of the legislation. In addition, there is uncertainty with respect to how these U.S. federal income tax changes will affect state and local taxation, which often uses federal taxable income as a starting point for computing state and local tax liabilities.

We continue to work with our tax advisors to determine the full impact that the recent tax legislation as a whole will have on us. We urge our investors to consult with their legal and tax advisors with respect to such legislation.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

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ITEM 2. PROPERTIES.

Our Properties

At December 31, 2018, we owned or controlled, primarily through long term leases, approximately 28,292 acres of coal land in Ohio, 1,060 acres of coal land in Maryland, 10,095 acres of coal land in Virginia, 359,122 acres of coal land in West Virginia, 81,868 acres of coal land in Wyoming, 268,802 acres of coal land in Illinois, 33,527 acres of coal land in Kentucky, 9,840 acres of coal land in Montana, 21,802 acres of coal land in New Mexico, 358 acres of coal land in Pennsylvania, and 19,146 acres of coal land in Colorado. In addition, we also owned or controlled through long term leases smaller parcels of property in Alabama, Indiana, Washington, Arkansas, California, Utah and Texas. We lease approximately 80,062 acres of our coal land from the federal government and approximately 22,385 acres of our coal land from various state governments. Certain of our preparation plants or loadout facilities are located on properties held under leases which expire at varying dates over the next 30 years. Most of the leases contain options to renew. Our remaining preparation plants and loadout facilities are located on property owned by us or for which we have a special use permit.

Our executive headquarters occupies leased office space at One CityPlace Drive, in St. Louis, Missouri. Our subsidiaries currently own or lease the equipment utilized in their mining operations. You should see “Our Mining Operations” for more information about our mining operations, mining complexes and transportation facilities.

Our Coal Reserves

We estimate that we owned or controlled approximately 1.9. billion tons of proven and probable recoverable reserves at December 31, 2018. Our coal reserve estimates at December 31, 2018 were prepared by our engineers and geologists and reviewed by Weir International, Inc., a mining and geological consultant. Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data. Our coal reserve estimates are periodically updated to reflect past coal production and other geologic and mining data. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam.

Our coal reserve estimates include reserves that can be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, our potential inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtaining mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. We use various assumptions in preparing our estimates of our coal reserves. You should see “Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs” contained in Item 1A, “Risk Factors.”

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The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2018:
Total Assigned Reserves
(Tons in millions)

	Total Assigned Recoverable Reserves			Sulfur Content (lbs. per million Btus)			As Received Btus per lb. (1)	Reserve Control		Mining Method		Past Reserve Estimates	
		Proven	Probable	<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Under-ground	2016	2017
Wyoming	911	906	5	867	44	—	8,844	911		911	—	1,115	1,025
Colorado	54	47	7	54	—	—	11,451	54	—	—	54	56	53
Central App.	57	52	5	17	40	—	13,061	56	1	20	37	70	69
Northern App.	73	63	10	3	70	—	13,243	11	62	—	73	48	35
Illinois	43	24	19	—	—	43	10,701	35	8	—	43	38	35
Total	1,138	1,092	46	941	154	43	9,529	1,067	71	931	207	1,327	1,217

(1) As received Btus per lb. includes the weight of moisture in the coal on an as sold basis.

Total Unassigned Reserves
(Tons in millions)

	Total Unassigned Recoverable Reserves			Sulfur Content (lbs. per million Btus)			As Received Btus per lb.(1)	Reserve Control		Mining Method	
		Proven	Probable	<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Underground
Wyoming	271	225	46	224	47	—	8,437	271	—	271	—
Colorado	—	—	—	—	—	—	—	—	—	—	—
Central App.	59	48	11	23	24	12	12,650	7	52	32	27
Northern App.	149	78	71	—	147	2	12,964	3	146	—	149
Illinois	281	187	94	—	—	281	11,172	63	218	2	279
Total	760	538	222	247	218	295	10,663	344	416	305	455

(1) As received Btus per lb. includes the weight of moisture in the coal on an as sold basis.

Federal and state legislation controlling air pollution affects the demand for certain types of coal by limiting the amount of sulfur dioxide which may be emitted as a result of fuel combustion and encourages a greater demand for low-sulfur coal. All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 63% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btus upon combustion, while an additional approximately 10% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Most of our reserves are suitable for the domestic steam coal markets. A substantial portion of the low-sulfur and compliance coal reserves at a number of our Appalachian mining complexes may also be used as metallurgical coal.
The carrying cost of our coal reserves at December 31, 2018 was $343 million, consisting of $5 million of prepaid royalties and a net book value of coal lands and mineral rights of $338 million.

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Reserve Acquisition Process

We acquire a significant portion of the coal we control in the western United States through the lease by application (LBA) process. Under this process, before a mining company can obtain new coal reserves, the coal tract must be nominated for lease, and the company must win the lease through a competitive bidding process. The LBA process can last anywhere from five to ten years or more from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves.

To initiate the LBA process, companies wanting to acquire additional coal must file an application with the BLM's state office indicating interest in a specific coal tract. The BLM reviews the initial application to determine whether the application conforms to existing land use plans for that particular tract of land and that the application would provide for maximum coal recovery. The application is further reviewed by a regional coal team at a public meeting. Based on a review of the available information and public comment, the regional coal team will make a recommendation to the BLM whether to continue, modify or reject the application.

If the BLM determines to continue the application, the company that submitted the application will pay for a BLM directed environmental analysis or an environmental impact statement to be completed. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other governmental agencies during this process, including state and federal agencies, surface management agencies, Native American tribes or bands, the U.S. Department of Justice or others as needed. The public comment period for an analysis or impact statement typically occurs over a 60 day period.

After the environmental analysis or environmental impact statement has been issued and a recommendation has been published that supports the lease sale of the LBA tract, the BLM schedules a public competitive lease sale. The BLM prepares an internal estimate of the fair market value of the coal that is based on its economic analysis and comparable sales analysis. Prior to the lease sale, companies interested in acquiring the lease must send sealed bids to the BLM. The bid amounts for the lease are payable in five annual installments, with the first 20% installment due when the mining operator submits its initial bid for an LBA. Before the lease is approved by the BLM, the company must first furnish to the BLM an initial rental payment for the first year of rent along with either a bond for the next 20% annual installment payment for the bid amount, or an application for history of timely payment, in which case the BLM may waive the bond requirement if the company successfully meets all the qualifications of a timely payor. The bids are opened at the lease sale. If the BLM decides to grant a lease, the lease is awarded to the company that submitted the highest total bid meeting or exceeding the BLM's fair market value estimate, which is not published. The BLM, however, is not required to grant a lease even if it determines that a bid meeting or exceeding the fair market value of the coal has been submitted. The winning bidder must also submit a report setting forth the nature and extent of its coal holdings to the U.S. Department of Justice for a 30 day antitrust review of the lease. If the successful bidder was not the initial applicant, the BLM will refund the initial applicant certain fees it paid in connection with the application process, for example the fees associated with the environmental analysis or environmental impact statement, and the winning bidder will bear those costs. Coal won through the LBA process and subject to federal leases are administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. In addition, we occasionally add small coal tracts adjacent to our existing LBAs through an agreed upon lease modification with the BLM. Once the BLM has issued a lease, the company must also complete the permitting process before it can mine the coal. Please refer to the section entitled "Environmental and Other Regulatory Matters" under Item 1.

Most of our federal coal leases have an initial term of 20 years and are renewable for subsequent 10 year periods and for so long thereafter as coal is produced in commercial quantities. These leases require diligent development within the first ten years of the lease award with a required coal extraction of 1.0% of the total coal under the lease by the end of that 10 year period. At the end of the 10 year development period, the lessee is required to maintain continuous operations, as defined in the applicable leasing regulations. In certain cases a lessee may combine contiguous leases into a logical mining unit, which we refer to as an LMU. This allows the production of coal from any of the leases within the LMU to be used to meet the continuous operation requirements for the entire LMU. Some of our mines are also subject to coal leases with applicable state regulatory agencies and have different terms and conditions that we must adhere to in a similar way to our federal leases. Under these federal and state leases, if the leased coal is not diligently developed during the initial 10 year development period or if certain other terms of the leases are not complied with, including the requirement to produce a minimum quantity of coal or pay a minimum production royalty, if applicable, the BLM or the applicable state regulatory agency can terminate the lease prior to the expiration of its term.

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On January 15, 2016, the federal government ordered a moratorium on new leases for coal mined from federal lands as part of a review of the government's management of federally-owned coal. In March 2017, the U.S. Secretary of Interior signed Secretarial Order 3348 lifting that moratorium and halting the Federal Coal Program Programmatic Environmental Impact Statement that was in process at the time. Litigation is currently pending in the United States District Court for the District of Montana challenging the lifting of the moratorium as a violation of the National Environmental Policy Act, the Mineral Leasing Act and the Federal Land Policy and Management Act. Although the Bureau of Land Management is now working to process coal lease applications and modifications expeditiously in accordance with regulations and guidance that existed before Secretarial Order 3338, which imposed the moratorium on new coal leases, any delay in the LBA process, including any delay caused by the now-lifted moratorium could prevent us from obtaining replacement reserves when we require them. Also, the outcome of the government's review is uncertain and could have a material and adverse impact on our business in any number of ways including by limiting our ability to mine reserves under ongoing or future applications, by increasing the costs or timeframe associated with obtaining leases under the LBA program, by making it uneconomical for us to participate in the programs or by preventing us from obtaining replacement reserves if the LBA program were to be terminated. Please see "Our inability to acquire additional coal reserves or our inability to develop coal reserves in an economically feasible manner may adversely affect our business," contained in Item 1A. "Risk Factors" for more information.

Title to Coal Property

Title to coal properties held by lessors or grantors to us and our subsidiaries and the boundaries of properties are normally verified at the time of leasing or acquisition. However, in cases involving less significant properties and consistent with industry practices, title and boundaries are not completely verified until such time as our independent operating subsidiaries prepare to mine such reserves. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine such reserves could be adversely affected. You should see "A defect in title or the loss of a leasehold interest in certain property or surface rights could limit our ability to mine our coal reserves or result in significant unanticipated costs" contained in Item 1A, "Risk Factors" for more information.

At December 31, 2018, approximately 26% of our coal reserves were held in fee, with the balance controlled by leases, most of which do not expire until the exhaustion of mineable and merchantable coal. Under current mining plans, substantially all reported leased reserves will be mined out within the period of existing leases or within the time period of assured lease renewals. Royalties are paid to lessors either as a fixed price per ton or as a percentage of the gross sales price of the mined coal. The majority of the significant leases are on a percentage royalty basis. In some cases, a payment is required, payable either at the time of execution of the lease or in annual installments. In most cases, the prepaid royalty amount is applied to reduce future production royalties.

From time to time, lessors or sublessors of land leased by our subsidiaries have sought to terminate such leases on the basis that such subsidiaries have failed to comply with the financial terms of the leases or that the mining and related operations conducted by such subsidiaries are not authorized by the leases. Some of these allegations relate to leases upon which we conduct operations material to our consolidated financial position, results of operations and liquidity, but we do not believe any pending claims by such lessors or sublessors have merit or will result in the termination of any material lease or sublease.

We leased approximately 57,859 acres of property to other coal operators in 2018. We received royalty income of $6.2 million during 2018 from the mining of approximately 2.3 million tons, $4.1 million during 2017 from the mining of approximately 1.2 million tons, $1.1 million during the period October 2 through December 31, 2016 from the mining of approximately 0.4 million tons, $1.7 million during the period January 1 through October 1, 2016 from the mining of approximately 0.6 million tons on those properties. We have included reserves at properties leased by us to other coal operators in the reserve figures set forth in this report.

ITEM 3. LEGAL PROCEEDINGS.

We are involved in various claims and legal actions arising in the ordinary course of business, including employee injury claims. After conferring with counsel, it is the opinion of management that the ultimate resolution of these claims, to the extent not previously provided for, will not have a material adverse effect on our consolidated financial condition, results of operations or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES.

The statement concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this Annual Report on Form 10-K for the period ended December 31, 2018.

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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 ("NYSE") under the symbol "ARCH" and has been trading since October 5, 2016 upon our emergence from bankruptcy. No prior established public trading market existed for this newly issued common stock prior to this date. Based upon information provided by our transfer agent, as of February 1, 2019, we had two stockholders of record. As many of our shares are held by brokers and other institutions on behalf of shareholders, we are unable to estimate the total number of beneficial holders of our common stock represented by these record holders.

Holders of our common stock are entitled to receive dividends when they are declared by our Board of Directors. We paid dividends on our common stock totaling $31.3 million in 2018. There is no assurance as to the amount or payment of dividends in the future because they will be subject to ongoing Board review and authorization will be based on a number of factors, including business and market conditions, the Company's future financial performance and other capital priorities.

The following table sets forth for each period indicated the dividends paid per common share and the per share high and low closing prices for our common stock as reported on the NYSE for the periods presented:

	High	Low	Dividends per common share
Year Ended December 31, 2018			
First quarter	$101.84	$83.84	$ 0.40
Second quarter	102.61	76.00	0.40
Third quarter	95.72	75.09	0.40
Fourth quarter	98.25	78.05	0.40
Year Ended December 31, 2017			
First quarter	$79.27	$63.24	$ —
Second quarter	77.59	60.13	0.35
Third quarter	81.09	67.39	0.35
Fourth quarter	94.57	68.95	0.35

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Stockholder Return Performance Presentation

The following graph compares the cumulative 27-month total return of holders of Arch Coal, Inc.'s common stock with the cumulative total returns of the S&P Midcap 400 index and two customized peer groups comprised of the following companies each: Cloud Peak Energy Inc., CNX Resources Corp and Westmoreland Coal Company in the 2017 Peer Group and Cloud Peak Energy, Inc., Consol Energy Inc., Peabody Energy Corp and Warrior Met Coal in the 2018 Peer Group. The graph assumes that the value of the investment in our common stock, the S&P Midcap 400 index, and in the respective peer groups (including reinvestment of dividends) was $100 on October 5, 2016 and tracks it through December 31, 2018.

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	10/5/2016	12/31/16	12/31/17	12/31/18
Arch Coal, Inc.	100.00	123.89	149.93	136.01
S&P Midcap 400	100.00	107.42	124.87	111.03
2017 Peer Group	100.00	99.01	87.92	60.23
2018 Peer Group	100.00	104.66	114.27	94.17

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Issuer Purchases of Equity Securities

During April 2017, the Board of Directors of Arch Coal, Inc. authorized a new share repurchase program for up to $300 million of its common stock. In October 2017, the Company's Board of Directors approved an incremental $200 million increase to the share repurchase program bringing the total authorization to $500 million. In July 2018, the Company's Board of Directors authorized an incremental $250 million increase to the share repurchase program bringing the total authorization to $750 million. The table below represents all share repurchases for the three months ended December 31, 2018:

Date	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan (in thousands)
October 1 through October 31, 2018	247,889	$ 92.78	247,889	$ 231,768
November 1 through November 30, 2018	449,180	$ 89.39	449,180	$ 191,615
December 1 through December 31, 2018	303,812	$ 83.93	303,812	$ 166,116
Total shares repurchased	1,000,881	$ 88.57	1,000,881	

As of December 31, 2018, we had repurchased 7,215,830 shares at an average share price of $80.92 per share for an aggregate purchase price of approximately $584 million since inception of the stock repurchase program, and the remaining
authorized amount for stock repurchases under this program is $166 million.
The timing of any future share repurchases, and the ultimate number of shares purchased, will depend on a number of factors, including business and market conditions, the Company's future financial performance and other capital priorities. The shares will be acquired in the open market or through private transactions in accordance with the Securities and Exchange Commission requirements. The share repurchase program has no termination date, but may be amended, suspended or discontinued at any time and does not commit the Company to repurchase shares of its common stock. The actual number and value of the shares to be purchased will depend on the performance of the Company's stock price and other market conditions.

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ITEM 6. SELECTED FINANCIAL DATA.

	Successor			Predecessor		
(In thousands, except per share data)	Year Ended December 31, 2018	Year Ended December 31, 2017	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Income Statement Data:			(1)	(1)	(2)	
Revenues	$2,451,787	$2,324,623	$575,688	$1,398,709	$2,573,260	$2,937,119
Asset impairment and mine closure costs	—	—	—	129,267	2,628,303	24,113
Income (loss) from operations	279,138	234,336	46,086	(255,423)	(2,865,063)	(149,531)
Interest expense	(20,471)	(26,905)	(11,241)	(135,888)	(397,979)	(390,946)
Non-operating expenses	(5,348)	(6,885)	(727)	1,626,113	(27,910)	—
Income (loss) from continuing operations	312,577	238,450	33,449	1,242,081	(2,913,142)	(558,353)
Basic earnings (loss) per common share	$15.90	$10.05	$1.34	$58.33	$(136.86)	$(26.31)
Diluted earnings (loss) per common share	$15.15	$9.84	$1.31	$58.28	$(136.86)	$(26.31)
Balance Sheet Data:						
Total assets	$1,887,060	$1,979,632	$2,136,597	$2,123,829	$5,041,881	$8,346,362
Working capital	549,448	496,913	566,391	522,465	(4,361,009)	1,023,357
Current maturities of debt	17,797	15,783	11,038	6,662	5,042,353	12,191
Long-term debt, less current maturities	300,186	310,134	351,841	353,272	30,953	5,064,818
Other long-term obligations	552,718	669,552	725,948	786,015	755,283	695,881
Noncurrent deferred income tax liability	—	—	—	—	—	422,809
Arch Coal stockholders' equity	704,821	665,865	746,577	687,483	(1,244,289)	1,668,154
Cash Flow Data:						
Cash provided by (used in) operating activities	417,963	396,474	84,192	(228,218)	(44,367)	(33,582)
Depreciation, depletion and amortization, including amortization of sales contracts, net	130,670	176,449	33,400	190,853	370,534	405,561
Capital expenditures	95,272	59,205	15,214	82,434	119,024	147,286
Net proceeds from the issuance of long term debt	—	298,500	—	—	—	(4,519)
Payments to retire debt, including redemption premium	—	(325,684)	—	—	—	—
Purchases of treasury stock	280,871	301,512	—	—		
Dividend payments	31,269	24,369	—	—	—	2,123
Operating Data:						
Tons sold	96,792	98,218	26,812	67,128	127,632	134,360
Tons produced	95,416	96,686	26,619	66,658	126,820	132,614
Tons purchased from third parties	1,140	1,532	193	481	1,287	1,182

(1) Our 2016 results were impacted by the filing of bankruptcy, subsequent emergence and the application of fresh start accounting. See Note 3 to the Consolidated Financial Statements, "Emergence from Bankruptcy and Fresh Start Accounting" for additional information.

(2) Our results in 2015 were impacted by further weakening of both the thermal and metallurgical coal markets. We incurred $2.6 billion of mine closure and asset impairment charges during the year; for additional information see

Note 6 to the Consolidated Financial Statements, “Impairment Charges and Mine Closure Costs.”

The selected financial information presented above for the years ended December 31, 2018 and 2017; the period October 2 through December 31, 2016, the period from January 1 through October 1, 2016, and the years ended December 31, 2015 and 2014 was derived from, and is qualified by, reference to our Consolidated Financial Statements, including the notes thereto, contained elsewhere herein. The selected financial information should be read in conjunction with the Consolidated Financial

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Statements and related notes and Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

As a result of the application of fresh start accounting as of the Plan Effective Date, the financial statements on or prior to October 1, 2016 are not comparable with the financial statements after October 1, 2016. References to “Successor” refer to the Company after October 1, 2016, after giving effect to the application of fresh start accounting; references to “Predecessor” refer to the Company on or prior to October 1, 2016.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Overview

Our results for the year ended December 31, 2018 benefited from continued strength in both the metallurgical and international thermal coal markets, while the domestic thermal market was largely stable. We believe seaborne coking coal markets remain well balanced, supported by moderate, continued growth in global steel production. Several coking coal supply disruptions led to meaningful increases in international coking coal pricing indices in the second half of 2018. While some coking coal supply has returned to the market, particularly from existing and formerly idled North American operations, global capital investment in new coking coal productive capacity remains limited. Steel tariffs appear to have had little impact on pricing or demand through the end of 2018, but longer term implications remain less certain. Recent indications of a slowing of the Chinese economy potentially have major implications for global economic growth generally and coking coal markets specifically. Future volatility in prompt international pricing may have a significant impact on our realized net back pricing as we have continued to sell more of our planned 2019 production volumes with pricing based on various indices or negotiated at the time of delivery.

Domestic thermal coal markets remained at levels that supported positive cash margins at all of our thermal operations throughout 2018. Natural gas prices remained tightly range bound for most of 2018 before increasing significantly late in the year. Storage levels of the competing fuel were below the ten year range for most of the second half of the current year, but production levels continue to increase and natural gas is expected to pressure domestic thermal coal demand in the long term. Generator coal stockpiles declined throughout the year on a tonnage basis, and are approaching historical averages based on days of burn. Powder River Basin coal remained economically competitive for electric generation in many regions throughout the country during 2018. Throughout the year, international thermal markets supported both Atlantic and Pacific export shipments from certain of our operations. We have continued to layer in forward positions in these markets at economically viable levels.

In the third quarter of 2017 we sold our Lone Mountain operation, which had been part of our Metallurgical segment. Lone Mountain’s results for the first nine months of 2017 are included in our full year 2017 results, and in all preceding periods’ results presented herein.

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Filing Under Chapter 11 of the United States Bankruptcy Code

On January 11, 2016 (the "Petition Date"), Arch Coal and substantially all of its wholly owned domestic subsidiaries (the "Filing Subsidiaries" and, together with Arch Coal, the "Debtors"; the Debtors, solely following the effective date of the Plan, the "Reorganized Debtors") filed voluntary petitions for reorganization (collectively, the "Bankruptcy Petitions") under Chapter 11 of Title 11 of the U.S. Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Eastern District of Missouri (the "Court"). The Debtors' Chapter 11 Cases (collectively, the "Chapter 11 Cases") were jointly administered under the caption In re Arch Coal, Inc., et al. Case No. 16-40120 (lead case). During the Chapter 11 Cases, each Debtor operated its business as a "debtor in possession" under the jurisdiction of the Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Court.

Upon emergence from bankruptcy on October 5, 2016, Arch Coal applied the provisions of fresh start accounting effective October 1, 2016 which resulted in Arch becoming a new entity for financial reporting purposes. Accordingly, the consolidated financial statements and accompanying footnotes on or after October 1, 2016 are not comparable to the consolidated financial statements prior to that date. References to "Successor" in the consolidated financial statements and footnotes are in reference to reporting dates on or after October 2, 2016; references to "Predecessor" in the consolidated financial statements and footnotes are in reference to reporting dates through October 1, 2016 which includes the impact of the Plan provisions and the application of fresh start accounting.

Results of Operations - Successor

Year Ended December 31, 2018 and 2017

Revenues. Our revenues include sales to customers of coal produced at our operations and coal purchased from third parties. Transportation costs are included in cost of coal sales and amounts billed by us to our customers for transportation are included in revenues.

Coal sales. The following table summarizes information about our coal sales for the years ended December 31, 2018 and 2017:

	Successor Year Ended December 31, 2018	Year Ended December 31, 2017	(Decrease) / Increase
	(In thousands)		
Coal sales	$2,451,787	$2,324,623	$127,164
Tons sold	96,792	98,218	(1,426)

On a consolidated basis, coal sales in 2018 increased approximately $127.2 million or 5.5% from 2017, while tons sold decreased approximately 1.4 million tons or 1.5%. Coal sales from ongoing Metallurgical operations increased approximately $223.7 million, primarily on increased pricing. Powder River Basin coal sales decreased approximately $50.9 million primarily due to decreased pricing, and Other Thermal coal sales increased approximately $32.4 million due to increased pricing. Lone Mountain, an operation that we divested in 2017, provided approximately $74.9 million in coal sales in the prior year. A net transportation related increase of approximately $36.8 million is included in the pricing increases discussed above. The increased transportation is primarily related to increased exports as a percentage of volume in the Metallurgical and Other Thermal segments. See discussion in "Operational Performance" for further information about segment results.

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Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for years ended December 31, 2018 and 2017:

	Successor		
	Year Ended December 31, 2018	Year Ended December 31, 2017	Increase / (Decrease) in Net Income
	(In thousands)		
Cost of sales (exclusive of items shown separately below)	$1,925,202	$1,839,993	$(85,209)
Depreciation, depletion and amortization	119,563	122,464	2,901
Accretion on asset retirement obligations	27,970	30,209	2,239
Amortization of sales contracts, net	11,107	53,985	42,878
Change in fair value of coal derivatives and coal trading activities, net	9,118	7,222	(1,896)
Selling, general and administrative expenses 149,314	100,300	87,952	(12,348)
Gain on sale of Lone Mountain Processing, Inc.	—	(21,297)	(21,297)
Other operating income, net	(20,611)	(30,241)	(9,630)
Total costs, expenses and other	$2,172,649	$2,090,287	$(82,362)

Cost of sales. Our cost of sales for year ended December 31, 2018 increased approximately $85.2 million or 4.6% versus 2017. The increase consists primarily of increased transportation costs (approximately $42.2 million), labor related costs (approximately $37.4 million), repairs and supplies costs (approximately $30.5 million), and a net increase in change in coal inventory costs (approximately $31.0 million) at ongoing operations. These cost increases were partially offset by the previously discussed sale of Lone Mountain which incurred approximately $75.2 million of cost of sales in the prior year. See discussion in "Operational Performance" for further information about segment results.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization costs for the year ended December 31, 2018 decreased versus 2017 due to reduced depreciation of plant and equipment and amortization of development costs of approximately $8.1 million. Of this total approximately $4.5 million is related to our Lone Mountain operation in the prior year. This reduction is partially offset by increased depletion of reserves of approximately $5.2 million primarily in our metallurgical segment.

Accretion on asset retirement obligation. Our accretion of asset retirement obligations for the year ended December 31, 2018, decreased versus 2017, primarily at idle properties where we have performed significant reclamation.

Amortization of sales contracts, net. The decrease in amortization of sales contracts, net in 2018 versus 2017 is primarily related to the value of certain Powder River Basin supply contracts being fully amortized at the end of 2017.

Change in fair value of coal derivatives and coal trading activities, net. The increased cost in 2018 versus the prior year is primarily related to mark-to-market losses on coal derivatives that we entered to hedge our price risk for anticipated international thermal coal shipments. As international thermal markets strengthened during the current year, the market value of these positions declined.

Selling, general and administrative expenses. The increase in selling, general and administrative expenses in 2018 versus 2017 is primarily due to increased compensation costs of approximately $9.0 million, of which approximately $6.1 million is stock based, and professional services of approximately $2.9 million.

Gain on sale of Lone Mountain Processing, Inc. During the year ended December 31, 2017, we sold Lone Mountain Processing Inc. and Cumberland River Coal LLC to Revelation Energy LLC, generating a gain of approximately $21.3 million. For further information on the sale of Lone Mountain Processing Inc. and Cumberland River Coal LLC to Revelation Energy LLC, please see Note 5 to the Consolidated Financial Statements, “Divestitures.”

Other operating income, net. The decreased benefit from other operating income, net in 2018 versus 2017 consists primarily of decreased income from equity investments (approximately $2.0 million), and the unfavorable impact of coal derivative settlements in the current year versus the prior year (approximately $8.5 million), partially offset by increased miscellaneous revenues including outlease royalty income, transloading fees, and net gains on asset sales (approximately $1.8 million).

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Non-operating expense. The following table summarizes non-operating expense for the years ended December 31, 2018 and 2017:

	Successor Year Ended December 31, 2018	Year Ended December 31, 2017	Increase / (Decrease) in Net Income
	(In thousands)		
Non-service related pension and postretirement benefit costs	$(3,202)	$ (1,940)	$ (1,262)
Net loss resulting from early retirement of debt and debt restructuring	(485)	(2,547)	2,062
Reorganization income (loss), net	(1,661)	(2,398)	737
Total nonoperating expense	$(5,348)	$ (6,885)	$ 1,537

Nonoperating expenses declined in the year ended December 31, 2018 versus 2017 primarily due to costs associated with our efforts to replace our securitization facility and term loan in the prior year, partially offset by costs associated with the repricing of our term loan in the current year, and reduced expenses associated with our Chapter 11 reorganization. Additionally, we adopted ASU 2017-07, “Compensation-Retirement Benefits (Topic 715) Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,” and now reflect these costs as nonoperating expenses. See further discussion in Note 3 to the Consolidated Financial Statements, “Emergence from Bankruptcy and Fresh Start Accounting”, and Note 13, “Debt and Financing Arrangements.”

Provision for (benefit from) income taxes. The following table summarizes our provision for income taxes for the years ended December 31, 2018 and 2017:

	Successor Year Ended December 31, 2018	Year Ended December 31, 2017	Increase / (Decrease) in Net Income
	(In thousands)		
Provision for (benefit from) income taxes	$(52,476)	$(35,255)	$ 17,221

See Note 14, to the Consolidated Financial Statements “Taxes,” for a reconciliation of the statutory federal income tax provision (benefit) at the statutory rate to the actual benefit from taxes.

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Operational Performance- Successor

Year Ended December 31, 2018 and 2017

Our mining operations are evaluated based on Adjusted EBITDAR, per-ton cash operating costs (defined as including all mining costs except depreciation, depletion, amortization, accretion on asset retirements obligations, and pass-through transportation expenses), and on other non-financial measures, such as safety and environmental performance. Adjusted EBITDAR is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization, the amortization of sales contracts, the accretion on asset retirement obligations, and non-operating income (expense) including reorganization items, net. Adjusted EBITDAR may also be adjusted for items that may not reflect the trend of future results by excluding transactions that are not indicative of our core operating performance. Adjusted EBITDAR is not a measure of financial performance in accordance with generally accepted accounting principles, and items excluded from Adjusted EBITDAR are significant in understanding and assessing our financial condition. Therefore, Adjusted EBITDAR should not be considered in isolation, nor as an alternative to net income, income from operations, cash flows from operations or as a measure of our profitability, liquidity or performance under generally accepted accounting principles. Furthermore, analogous measures are used by industry analysts to evaluate the Company’s operating performance. Investors should be aware that our presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies.

The following table shows operating results of coal operations for the years ended December 31, 2018 and 2017.

	Successor Year Ended December 31, 2018	Year Ended December 31, 2017	Variance
Powder River Basin			
Tons sold (in thousands)	79,542	80,604	(1,062)
Coal sales per ton sold	$ 12.03	$ 12.49	$ (0.46)
Cash cost per ton sold	$ 10.45	$ 10.53	$ 0.08
Cash margin per ton sold	$ 1.58	$ 1.96	$ (0.38)
Adjusted EBITDAR (in thousands)	$ 126,525	$ 158,882	$ (32,357)
Metallurgical			
Tons sold (in thousands)	7,747	8,192	(445)
Coal sales per ton sold	$ 111.72	$ 90.17	$ 21.55
Cash cost per ton sold	$ 66.85	$ 60.76	$ (6.09)
Cash margin per ton sold	$ 44.87	$ 29.41	$ 15.46
Adjusted EBITDAR (in thousands)	$ 349,524	$ 243,616	$ 105,908
Other Thermal			
Tons sold (in thousands)	9,089	9,205	(116)
Coal sales per ton sold	$ 36.06	$ 34.85	$ 1.21
Cash cost per ton sold	$ 28.95	$ 24.20	$ (4.75)
Cash margin per ton sold	$ 7.11	$ 10.65	$ (3.54)
Adjusted EBITDAR (in thousands)	$ 68,620	$ 102,006	$ (33,386)

This table reflects numbers reported under a basis that differs from U.S. GAAP. See the “Reconciliation of Non-GAAP measures” below for explanation and reconciliation of these amounts to the nearest GAAP figures. Other companies may calculate these per ton amounts differently, and our calculation may not be comparable to other similarly titled measures.

Powder River Basin — Adjusted EBITDAR for the year ended December 31, 2018, declined from the year ended December 31, 2017. Pricing in the current year was negatively impacted by the annual roll off and replacement of a portion of our term contracts at the end of the prior year. Some of these prior year contracts had been executed during stronger market environments. Increased natural gas and wind generation and above normal generator coal stockpiles pressured Powder River Basin markets throughout the current year. Volume decreased year over year reflecting the increase in electric generation from competing fuels and above normal generator stockpiles, offset to some degree by our ability to capitalize on shipping disruptions at other mines in the basin precipitated by excessive rainfall. Cash cost per ton sold declined year over year despite inflationary pressure, particularly for diesel fuel. Our efforts to "right size" our Powder River Basin operations coupled with lower sales sensitive costs, offset inflationary pressures, particularly diesel fuel.

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Metallurgical — Adjusted EBITDAR for the year ended December 31, 2018, increased from the year ended December 31, 2017 due to significant pricing improvement, and pricing continues to be supported by strength in international and domestic steel markets. Throughout the current year our pricing benefited from our decision to commit less of our planned production to North American annual fixed price contracts, leaving a greater portion exposed to stronger pricing in the international coking coal markets. Our sales volume decline versus the prior year was effectively all related to the divestiture of Lone Mountain. Lone Mountain sold approximately 1.0 million tons in the prior year. Tons sold from ongoing operations increased over 0.5 million tons versus the prior year. Our cash cost per ton sold for the year ended December 31, 2018, increased versus the prior year due to increased operating tax and royalty costs, increased labor costs, and inflationary pressure on parts, supplies, and services, as well as the timing of some major repairs. Inflationary pressure on labor, goods, and services utilized in our metallurgical segment has continued to build throughout the current year as the coking coal industry in the Appalachian geographic region attempts to maximize production to take advantage of the currently strong coking coal markets. Operating taxes and royalties are impacted by the increase in coal sales per ton sold and an increase in the severance tax rate at our Beckley Mine.

Our metallurgical segment sold 6.7 million tons of coking coal and 1.1 million tons of associated thermal coal in the year ended December 31, 2018, as compared to 6.4 million tons of coking coal, 0.5 million tons of PCI coal, and 1.3 million tons of associated thermal coal in the prior year. Longwall operations accounted for approximately 71% of our shipment volume in the current year and 57% of our shipment volume in the prior year.

Other Thermal— Adjusted EBITDAR for the year ended December 31, 2018 declined from the year ended December 31, 2017. The current year was pressured by lower sales and production volume at our West Elk operation and increased costs at our West Elk and Coal-Mac operations. West Elk costs increased due to higher levels of continuous miner production as compared to the prior year, which was necessary to maintain adequate longwall development. Inflationary pressure further impacted costs, particularly materials, supplies, and diesel fuel.

Period from October 2 through December 31, 2016

Revenues. Our revenues include sales to customers of coal produced at our operations and coal purchased from third parties. Transportation costs are included in cost of coal sales and amounts billed by us to our customers for transportation are included in revenues.

Coal sales. The following table summarizes information about our coal sales for the period from October 2 through December 31, 2016:

	Successor October 2 through December 31, 2016 (In thousands)
Coal sales	$ 575,688
Tons sold	26,812

Coal sales for the period from October 2 through December 31, 2016 by segment were approximately 48% Powder River Basin, 35% Metallurgical, and 17% Other. Tons sold for the period by segment were approximately 81% Powder River Basin, 9% Metallurgical, and 10% Other. See discussion in “Operational Performance” below for further information about regional results.

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Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for the period from October 2 through December 31, 2016:

	Successor October 2 through December 31, 2016
Cost of sales (exclusive of items shown separately below)	$470,319
Depreciation, depletion and amortization	32,604
Accretion on asset retirement obligations	7,634
Amortization of sales contracts, net	796
Change in fair value of coal derivatives and coal trading activities, net	396
Selling, general and administrative expenses	23,193
Other operating income, net	(5,340)
Total costs, expenses and other	$529,602

Cost of sales. For the period from October 2 through December 31, 2016, our cost of sales consisted primarily of labor related costs (approximately 25%), repairs and supplies (approximately 33%), operating taxes and royalties (approximately 22%), and transportation costs (approximately 12%). See discussion in “Operational Performance” below for information about segment cost results.

Depreciation, depletion and amortization. For the period from October 2 through December 31, 2016 our depreciation, depletion and amortization costs consist of depreciation of plant and equipment (approximately 63%), depletion of reserves (approximately 20%), and amortization of development costs (approximately 17%). This reflects the application of fresh start accounting. For further information on fresh start accounting, please see Note 3 to the Consolidated Financial Statements, “Emergence from Bankruptcy and Fresh Start Accounting.”

Accretion on asset retirement obligation. For the period from October 2 through December 31, 2016 approximately 66% of the accretion on our asset retirement obligation is attributable to our large surface operations in the Powder River Basin.

Selling, general and administrative expenses. For the period from October 2 through December 31, 2016, selling, general and administrative expenses consist primarily of compensation costs of $15.7 million, and professional services and usage and maintenance agreements of $5.1 million.

Other operating income, net. For the period from October 2 through December 31, 2016 other operating income, net consists primarily of miscellaneous revenues including royalties and net gains on asset sales of $5.0 million and net income from equity investments of $1.7 million, partially offset by miscellaneous expenses primarily related to our land company of $1.4 million.

Non-operating expense. The following table summarizes non-operating expense for the period from October 2 through December 31, 2016:

	Successor October 2 through December 31, 2016

	(In thousands)
Non-service related pension and postretirement benefit costs	$ 32
Reorganization income (loss), net	(759)
Total nonoperating expense	$ (727)

Nonoperating expenses for the period from October 2 through December 31, 2016 are expenses associated with our Chapter 11 reorganization. Additionally, we adopted ASU 2017-07, “Compensation-Retirement Benefits (Topic 715) Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,” and now reflect these costs as nonoperating expenses. See further discussion in Note 3 to the Consolidated Financial Statements, “Emergence from Bankruptcy and Fresh Start Accounting”.”

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Provision for (benefit from) income taxes. The following table summarizes our provision for income taxes for the period from October 2 through December 31, 2016:

	Successor October 2 through December 31, 2016 (In thousands)
Provision for (benefit from) income taxes	$ 1,156

See Note 14, to the Consolidated Financial Statements "Taxes," for a reconciliation of the statutory federal income tax provision (benefit) at the statutory rate to the actual benefit from taxes.

Operational Performance- Successor

Period from October 2 through December 31, 2016

Our mining operations are evaluated based on Adjusted EBITDAR, per-ton cash operating costs (defined as including all mining costs except depreciation, depletion, amortization, accretion on asset retirements obligations, and pass-through transportation expenses), and on other non-financial measures, such as safety and environmental performance. Adjusted EBITDAR is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization, the amortization of sales contracts, the accretion on asset retirement obligations, and non-operating income (expense) including reorganization items, net. Adjusted EBITDAR may also be adjusted for items that may not reflect the trend of future results by excluding transactions that are not indicative of our core operating performance. Adjusted EBITDAR is not a measure of financial performance in accordance with generally accepted accounting principles, and items excluded from Adjusted EBITDAR are significant in understanding and assessing our financial condition. Therefore, Adjusted EBITDAR should not be considered in isolation, nor as an alternative to net income, income from operations, cash flows from operations or as a measure of our profitability, liquidity or performance under generally accepted accounting principles. Furthermore, analogous measures are used by industry analysts to evaluate the Company's operating performance. Investors should be aware that our presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies.

The following table shows operating results of coal operations for the period from October 2 through December 31, 2016.

	Successor October 2 through December 31, 2016
Powder River Basin	
Tons sold (in thousands)	21,824
Coal sales per ton sold	$ 12.41
Cash cost per ton sold	$ 9.88
Cash margin per ton sold	$ 2.53
Adjusted EBITDAR (in thousands)	$ 55,765
Metallurgical	

Tons sold (in thousands)	2,442
Coal sales per ton sold	$ 65.61
Cash cost per ton sold	$ 52.98
Cash margin per ton sold	$ 12.63
Adjusted EBITDAR (in thousands)	$ 30,819
Other Thermal	
Tons sold (in thousands)	2,510
Coal sales per ton sold	$ 34.01
Cash cost per ton sold	$ 21.79
Cash margin per ton sold	$ 12.22
Adjusted EBITDAR (in thousands)	$ 31,159

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This table reflects numbers reported under a basis that differs from U.S. GAAP. See the "Reconciliation of Non-GAAP measures" below for explanation and reconciliation of these amounts to the nearest GAAP figures. Other companies may calculate these per ton amounts differently, and our calculation may not be comparable to other similarly titled measures.

Powder River Basin — Adjusted EBITDAR for the period from October 2 through December 31, 2016 benefited from cost control efforts and rebounding demand driven by rising natural gas prices that increased the competitiveness of Powder River Basin coal for electric generation versus the competing fuel. Rising gas prices resulted from favorable summer heat, increased natural gas exports, both pipeline and liquefied natural gas, and flat to slightly declining natural gas production. Cost control efforts included adjusting operations to align with current market volume expectations.

Metallurgical — Adjusted EBITDAR for the period from October 2 through December 31, 2016 benefited from the significant increase in international pricing for metallurgical coal. Supply shortages driven by a Chinese mandate to restrict its domestic supply, supply rationalization in North America, years of global underinvestment in the industry, and some specific international supply disruptions, particularly in Australia, resulted in a significant increase in international prompt metallurgical coal prices. Our ability to take advantage of the rapid increase in prompt international pricing was muted due to having significant volumes for the period committed and priced prior to the rapid increase. Our metallurgical segment sold 1.9 million tons of metallurgical coal and 0.5 million tons of associated thermal coal in the period from October 2 through December 31, 2016. Longwall operations accounted for approximately 55% of our shipment volume in the period. Late in the period prompt international metallurgical pricing began to retreat as loosening of Chinese supply restrictions and easing of supply disruptions began to mitigate the supply shortage.

Other Thermal— Adjusted EBITDAR for the period from October 2 through December 31, 2016 benefited from the increased natural gas pricing discussed in the Powder River Basin segment above, and increased international thermal prices. These benefits were primarily recognized at our West Elk operation where domestic opportunities increased and export opportunities became economic. Partially offsetting those positive trends were operating issues at our Viper operation's largest customer that significantly reduced sales volume in the period.

Results of Operations - Predecessor

Period from January 1 through October 1, 2016

Revenues. Our revenues include sales to customers of coal produced at our operations and coal purchased from third parties. Transportation costs are included in cost of coal sales and amounts billed by us to our customers for transportation are included in revenues.

Coal sales. The following table summarizes information about our coal sales for the period from January 1 through October 1, 2016:

	Predecessor January 1 through October 1, 2016
	(In thousands)
Coal sales	$1,398,709
Tons sold	67,128

Coal sales for the period from January 1 through October 1, 2016 by segment were approximately 52% Powder River Basin, 31% Metallurgical, and 15% Other. Tons sold for the period by segment were approximately 82% Powder River Basin, 10% Metallurgical, and 8% Other. See discussion in “Operational Performance” below for further information about regional results.

Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for the period from January 1 through October 1, 2016:

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	Predecessor January 1 through October 1, 2016
	(In thousands)
Cost of sales (exclusive of items shown separately below)	$ 1,262,174
Depreciation, depletion and amortization	191,581
Accretion on asset retirement obligations	24,321
Amortization of sales contracts, net	(728)
Change in fair value of coal derivatives and coal trading activities, net	2,856
Asset impairment and mine closure costs	129,267
Selling, general and administrative expenses	59,918
Other operating income, net	(15,257)
Total costs, expenses and other	$ 1,654,132

Cost of sales. Our cost of sales for the period from January 1 through October 1, 2016 consisted primarily of labor related costs (approximately 28%), repairs and supplies (approximately 34%), operating taxes and royalties (approximately 21%), and transportation costs (approximately 10%). See discussion in "Operational Performance" below for information about segment cost results.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization costs for the period from January 1 through October 1, 2016 consist of depreciation of plant and equipment (approximately 55%), depletion of reserves (approximately 34%), and amortization of development costs (approximately 11%).

Accretion on asset retirement obligation. Approximately 70% of the accretion on our asset retirement obligation for the period from January 1 through October 1, 2016 was attributable to our large surface operations in the Powder River Basin.

Asset impairment and mine closure costs. During the period from January 1 through October 1, 2016 we received notification of intent to idle operations by a third party to whom we leased certain Appalachian reserves. As a result of the idling and weakness in the thermal coal market, we determined that the value of these reserves was impaired. Also during this period we relinquished our interest in Millennium Bulk Terminal while retaining future throughput rights. As a result of the sale, our remaining equity investment in Millennium was impaired.

Selling, general and administrative expenses. Total selling, general and administrative expenses for the period from January 1 through October 1, 2016 consist primarily of compensation costs of $39.0 million, and professional services and usage and maintenance agreements of $12.0 million.

Other operating income, net. Other operating income, net for the period from January 1 through October 1, 2016 consists primarily of miscellaneous revenues including royalties and net gains on asset sales of $18.1 million and net income from equity investments of $5.3 million, partially offset by miscellaneous expenses primarily related to our land company of $8.1 million.

Non-operating expense. The following table summarizes non-operating expense for the period from January 1 through October 1, 2016.

Predecessor
January 1
through

	October 1, 2016 (In thousands)
Non-service related pension and postretirement benefit costs	$(1,715)
Net loss resulting from early retirement of debt and debt restructuring	(2,213)
Reorganization income (loss), net	1,630,041
Total non-operating (expense) benefit	$1,626,113

Nonoperating expenses in the period from January 1 through October 1, 2016 related to our various debt restructuring activities and Chapter 11 reorganization. Additionally, we adopted ASU 2017-07, “Compensation-Retirement Benefits (Topic

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715) Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost," and now reflect these costs as nonoperating expenses. For further information on our successful reorganization, please see Note 3 to the Consolidated Financial Statements, "Emergence from Bankruptcy and Fresh Start Accounting."

Benefit from income taxes. The following table summarizes our benefit from income taxes for the period from January 1 through October 1, 2016.

	Predecessor January 1 through October 1, 2016 (In thousands)
Benefit from income taxes	$ (4,626)

See Note 14, to the Consolidated Financial Statements "Taxes," for a reconciliation of the statutory federal income tax provision (benefit) at the statutory rate to the actual benefit from taxes.

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Operational Performance - Predecessor

Our mining operations are evaluated based on Adjusted EBITDAR, per-ton cash operating costs (defined as including all mining costs except depreciation, depletion, amortization, accretion on asset retirements obligations, and pass-through transportation expenses), and on other non-financial measures, such as safety and environmental performance. Adjusted EBITDAR is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization, the amortization of sales contracts, the accretion on asset retirement obligations, and non-operating income (expense) including reorganization items, net. Adjusted EBITDAR may also be adjusted for items that may not reflect the trend of future results by excluding transactions that are not indicative of our core operating performance. Adjusted EBITDAR is not a measure of financial performance in accordance with generally accepted accounting principles, and items excluded from Adjusted EBITDAR are significant in understanding and assessing our financial condition. Therefore, Adjusted EBITDAR should not be considered in isolation, nor as an alternative to net income, income from operations, cash flows from operations or as a measure of our profitability, liquidity or performance under generally accepted accounting principles. Furthermore, analogous measures are used by industry analysts to evaluate the Company's operating performance. Investors should be aware that our presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies.

The following table shows operating results of coal operations for the Predecessor periods January 1 through October 1, 2016:

	Predecessor January 1 through October 1, 2016
Powder River Basin	
Tons sold (in thousands)	54,911
Coal sales per ton sold	$ 13.01
Cash cost per ton sold	$ 10.95
Cash margin per ton sold	$ 2.06
Adjusted EBITDAR (in thousands)	$ 113,185
Metallurgical	
Tons sold (in thousands)	6,692
Coal sales per ton sold	$ 53.15
Cash cost per ton sold	$ 51.40
Cash margin per ton sold	$ 1.75
Adjusted EBITDAR (in thousands)	$ 11,851
Other Thermal	
Tons sold (in thousands)	5,181
Coal sales per ton sold	$ 36.16
Cash cost per ton sold	$ 30.28
Cash margin per ton sold	$ 5.88
Adjusted EBITDAR (in thousands)	$ 31,448

This table reflects numbers reported under a basis that differs from U.S. GAAP. See the "Reconciliation of Non-GAAP measures" below for explanation and reconciliation of these amounts to the nearest GAAP figures. Other companies may calculate these per ton amounts differently, and our calculation may not be comparable to other similarly titled measures.

Powder River Basin — Adjusted EBITDAR for the period from January 1 through October 1, 2016 was negatively impacted by demand destruction driven by historically low natural gas prices that limited the competitiveness of Powder River Basin coal for electric generation versus the competing fuel. The low natural gas prices were driven by mild winter weather and record natural gas production levels.

Metallurgical — Adjusted EBITDAR for the period from January 1 through October 1, 2016 was negatively impacted by declines in metallurgical coal prices. Years of global oversupply from anemic economic growth and international overproduction, particularly from Australia, drove pricing down to levels that were unprofitable for most North American producers. Our metallurgical segment sold 5.1 million tons of metallurgical coal and 1.6 million tons of associated thermal coal in the period from January 1 through October 1, 2016. During the period we continued shifting volume to our lower cost Leer operation. Longwall operations accounted for approximately 65% of our shipment volume in the period.

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Other Thermal— Adjusted EBITDAR for the period from January 1 through October 1, 2016 was negatively impacted by demand destruction driven by historically low natural gas prices discussed in the Powder River Basin segment above, and the lack of economic export opportunities. These conditions severely restricted tons sold and coal sales per ton sold at our West Elk and Coal Mac operations.

Reconciliation of NON-GAAP measures

Non-GAAP Segment coal sales per ton sold

Non-GAAP Segment coal sales per ton sold is calculated as segment coal sales revenues divided by segment tons sold. Segment coal sales revenues are adjusted for transportation costs, and may be adjusted for other items that, due to generally accepted accounting principles, are classified in “other income” on the consolidated income statements, but relate to price protection on the sale of coal. Segment coal sales per ton sold is not a measure of financial performance in accordance with generally accepted accounting principles. We believe segment coal sales per ton sold provides useful information to investors as it better reflects our revenue for the quality of coal sold and our operating results by including all income from coal sales. The adjustments made to arrive at these measures are significant in understanding and assessing our financial condition. Therefore, segment coal sales revenues should not be considered in isolation, nor as an alternative to coal sales revenues under generally accepted accounting principles.

Year Ended December 31, 2018	Successor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Revenues in the Consolidated Income Statements	$973,248	$ 1,036,621	$428,884	$13,034	$ 2,451,787
Less: Adjustments to reconcile to Non-GAAP Segment coal sales revenue					
Coal risk management derivative settlements classified in "other income"	—	—	8,718	—	8,718
Coal sales revenues from idled or otherwise disposed operations not included in segments	—	—	—	13,034	13,034
Transportation costs	16,388	171,126	92,438	—	279,952
Non-GAAP Segment coal sales revenues	$956,860	$ 865,495	$327,728	$—	$ 2,150,083
Tons sold	79,542	7,747	9,089		
Coal sales per ton sold	$12.03	$ 111.72	$36.06		

Year Ended December 31, 2017	Successor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Revenues in the Consolidated Income Statements	$1,024,197	$ 887,839	$396,504	$16,083	$ 2,324,623
Less: Adjustments to reconcile to Non-GAAP Segment coal sales revenue					
Coal risk management derivative settlements classified in "other income"	—	—	200	—	200
Coal sales revenues from idled or otherwise disposed operations not included in segments	—	—	—	15,061	15,061

Transportation costs	17,437	149,212	75,491	1,022	243,162
Non-GAAP Segment coal sales revenues	$ 1,006,760	$ 738,627	$ 320,813	$ —	$ 2,066,200
Tons sold	80,604	8,192	9,205		
Coal sales per ton sold	$ 12.49	$ 90.17	$ 34.85		

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October 2 through December 31, 2016	Successor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Revenues in the Consolidated Income Statements	$275,703	$ 200,377	$97,382	$2,226	$575,688
Less: Adjustments to reconcile to Non-GAAP Segment coal sales revenue					
Coal risk management derivative settlements classified in "other income"	—	—	(112)	—	(112)
Coal sales revenues from idled or otherwise disposed operations not included in segments	—	—	—	2,181	2,181
Transportation costs	4,826	40,170	12,130	45	57,171
Non-GAAP Segment coal sales revenues	$270,877	$ 160,207	$85,364	$—	$516,448
Tons sold	21,824	2,442	2,510		
Coal sales per ton sold	$12.41	$ 65.61	$34.01		

January 1 through October 1, 2016	Predecessor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Revenues in the Consolidated Income Statements	$726,747	$ 437,069	$213,052	$21,841	$1,398,709
Less: Adjustments to reconcile to Non-GAAP Segment coal sales revenue					
Coal risk management derivative settlements classified in "other income"	—	—	448	—	448
Coal sales revenues from idled or otherwise disposed operations not included in segments	—	—	—	19,368	19,368
Transportation costs	12,559	81,390	25,252	2,473	121,674
Non-GAAP Segment coal sales revenues	$714,188	$ 355,679	$187,352	$—	$1,257,219
Tons sold	54,911	6,692	5,181		
Coal sales per ton sold	$13.01	$ 53.15	$36.16		

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Non-GAAP Segment cash cost per ton sold

Non-GAAP Segment cash cost per ton sold is calculated as segment cash cost of coal sales divided by segment tons sold. Segment cash cost of coal sales is adjusted for transportation costs, and may be adjusted for other items that, due to generally accepted accounting principles, are classified in “other income” on the consolidated income statements, but relate directly to the costs incurred to produce coal. Segment cash cost per ton sold is not a measure of financial performance in accordance with generally accepted accounting principles. We believe segment cash cost per ton sold better reflects our controllable costs and our operating results by including all costs incurred to produce coal. The adjustments made to arrive at these measures are significant in understanding and assessing our financial condition. Therefore, segment cash cost of coal sales should not be considered in isolation, nor as an alternative to cost of sales under generally accepted accounting principles.

Year Ended December 31, 2018	Successor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Cost of sales in the Consolidated Income Statements	$851,414	$ 689,053	$355,544	$29,191	$1,925,202
Less: Adjustments to reconcile to Non-GAAP Segment cash cost of coal sales					
Diesel fuel risk management derivative settlements classified in "other income"	4,056	—	—	—	4,056
Transportation costs	16,388	171,126	92,438	—	279,952
Cost of coal sales from idled or otherwise disposed operations not included in segments	—	—	—	18,884	18,884
Other (operating overhead, certain actuarial, etc.)	—	—	—	10,307	10,307
Non-GAAP Segment cash cost of coal sales	830,970	517,927	263,106	—	1,612,003
Tons sold	79,542	7,747	9,089		
Cash Cost Per Ton Sold	$10.45	$ 66.85	$28.95		

Year Ended December 31, 2017	Successor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Cost of sales in the Consolidated Income Statements	$863,836	$ 646,911	$298,229	$31,017	$1,839,993
Less: Adjustments to reconcile to Non-GAAP Segment cash cost of coal sales					
Diesel fuel risk management derivative settlements classified in "other income"	(2,645)	—	—	—	(2,645)
Transportation costs	17,437	149,212	75,491	1,022	243,162
Cost of coal sales from idled or otherwise disposed operations not included in segments	—	—	—	28,065	28,065
Other (operating overhead, certain actuarial, etc.)	—	—	—	1,930	1,930
Non-GAAP Segment cash cost of coal sales	$849,044	$ 497,699	$222,738	$—	$1,569,481
Tons sold	80,604	8,192	9,205		
Cash Cost Per Ton Sold	$10.53	$ 60.76	$24.20		

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October 2 through December 31, 2016	Successor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Cost of sales in the Consolidated Income Statements	$220,714	$ 169,532	$66,811	$13,262	$470,319
Less: Adjustments to reconcile to Non-GAAP Segment cash cost of coal sales					
Diesel fuel risk management derivative settlements classified in "other income"	363	—	—	—	363
Transportation costs	4,825	40,171	12,130	45	57,171
Cost of coal sales from idled or otherwise disposed operations not included in segments	—	—	—	5,853	5,853
Fresh start coal inventory fair value adjustment	—	—	—	7,345	7,345
Other (operating overhead, certain actuarial, etc.)	—	—	—	19	19
Non-GAAP Segment cash cost of coal sales	$215,526	$ 129,361	$54,681	$—	$399,568
Tons sold	21,824	2,442	2,510		
Cash Cost Per Ton Sold	$9.88	$ 52.98	$21.79		

January 1 through October 1, 2016	Predecessor Powder River Basin	Metallurgical	Other Thermal	Idle and Other	Consolidated
(In thousands)					
GAAP Cost of sales in the Consolidated Income Statements	$610,734	$ 425,345	$181,872	$44,223	$1,262,174
Less: Adjustments to reconcile to Non-GAAP Segment cash cost of coal sales					
Diesel fuel risk management derivative settlements classified in "other income"	(3,361)	—	(276)	(59)	(3,696)
Transportation costs	12,560	81,389	25,253	2,472	121,674
Cost of coal sales from idled or otherwise disposed operations not included in segments	—	—	—	42,513	42,513
Other (operating overhead, certain actuarial, etc.)	—	—	—	(703)	(703)
Non-GAAP Segment cash cost of coal sales	$601,535	$ 343,956	$156,895	$—	$1,102,386
Tons sold	54,911	6,692	5,181		
Cash Cost Per Ton Sold	$10.95	$ 51.40	$30.28		

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Reconciliation of Segment Adjusted EBITDAR to Net Income

The discussion in “Results of Operations” above includes references to our Adjusted EBITDAR for each of our reportable segments. Adjusted EBITDAR is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization, the amortization of sales contracts, the accretion on asset retirement obligations, and reorganization items, net. Adjusted EBITDAR may also be adjusted for items that may not reflect the trend of future results by excluding transactions that are not indicative of our core operating performance. We use Adjusted EBITDAR to measure the operating performance of our segments and allocate resources to our segments. Adjusted EBITDAR is not a measure of financial performance in accordance with generally accepted accounting principles, and items excluded from Adjusted EBITDAR are significant in understanding and assessing our financial condition. Therefore, Adjusted EBITDAR should not be considered in isolation, nor as an alternative to net income, income from operations, cash flows from operations or as a measure of our profitability, liquidity or performance under generally accepted accounting principles. Investors should be aware that our presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies. The table below shows how we calculate Adjusted EBITDAR.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	October 2 through December 31, 2016	January 1 through October 1, 2016
(In thousands)				
Net income	$312,577	$238,450	$33,449	$1,242,081
Income tax benefit (provision)	(52,476)	(35,255)	1,156	(4,626)
Interest expense, net	13,689	24,256	10,754	133,235
Depreciation, depletion and amortization	119,563	122,464	32,604	191,581
Accretion on asset retirement obligations	27,970	30,209	7,634	24,321
Amortization of sales contracts, net	11,107	53,985	796	(728)
Asset impairment and mine closure costs	—	—	—	129,267
Gain on sale of Lone Mountain Processing, Inc.	—	(21,297)	—	—
Net loss resulting from early retirement of debt and debt restructuring	485	2,547	—	2,213
Non-service related postretirement benefit costs	3,202	1,940	(32)	1,715
Reorganization items, net	1,661	2,398	759	(1,630,041)
Fresh start coal inventory fair value adjustment	—	—	7,345	—
Adjusted EBITDAR	437,778	419,697	94,465	89,018
EBITDAR from idled or otherwise disposed operations	2,492	3,253	1,596	10,155
Selling, general and administrative expenses	100,300	87,952	23,193	59,919
Other	4,099	(6,398)	(1,511)	(2,608)
Segment Adjusted EBITDAR from coal operations	$544,669	$504,504	$117,743	$156,484

Other includes primarily income from our equity investments, certain changes in the fair value of coal derivatives and coal trading activities, certain changes in fair value of heating oil derivatives we use to manage our exposure to diesel fuel pricing, net EBITDAR provided by our land company, and certain miscellaneous revenue.

Other for the year ended December 31, 2018, reduced EBITDAR approximately $4.1 million versus providing approximately $6.4 million in EBITDAR in year ended December 31, 2017. The decline in EBITDAR was primarily related to unfavorable change in value of heating oil derivatives of approximately $6.1 million, unfavorable change in value of coal derivatives of approximately $2.2 million, and reduced income from equity investments of approximately $2.0 million.

For the Successor period from October 2 through December 31, 2016, other consists primarily of net income from equity investments of $1.7 million.

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For the Predecessor period from January 1 through October 1, 2016, other consists primarily of net income from equity investments of $5.3 million and favorable change in value of heating oil derivatives of approximately $4.5 million partially offset by a net reduction in EBITDAR from our land company of approximately $5.5 million and unfavorable change in the value of coal derivatives of approximately $3.3 million.

Liquidity and Capital Resources

Our primary sources of liquidity are proceeds from coal sales to customers and certain financing arrangements. Excluding significant investing activity, we intend to satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations and cash on hand. Our focus is prudently managing costs, including capital expenditures, maintaining a strong balance sheet, and ensuring adequate liquidity.

On April 27, 2017, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock. On October 26, 2017 our Board of Directors authorized an additional $200 million for our share repurchase program, bringing the total authorization to $500 million. On July 26, 2018, our Board of Directors authorized an additional $250 million for our share repurchase program, bringing the total authorization to $750 million. During the year ended