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, 2016

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	NYSE

Securities registered pursuant to Section 12(g) of the Act: None

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

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

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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, 2016** was approximately $6.4 million.

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

At February 16, 2017 there were 25,001,819 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 2017 annual stockholders’ meeting to be held on May 4, 2017 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 31 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," "should," "will" or 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 recent emergence from Chapter 11 bankruptcy protection;
- market demand for coal 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;
- 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;
- disruptions in the quantities of coal produced by our contract mine operators;
- our ability to collect payments from our customers;
- defects in title or the loss of a leasehold interest;
- railroad, barge, truck 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 deferral of contracted shipments of coal by our customers;
- our ability to service our outstanding indebtedness;
- our ability to comply with the restrictions imposed by our Term Loan Agreement, our Securitization Facility, 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;

- 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;
- our ability to continue as a going concern; 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.

PART I

ITEM 1. BUSINESS

Introduction

We are one of the world's largest coal producers. For the year ended December 31, 2016, we sold approximately 94 million tons of coal, including approximately 0.7 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, 2016, we operated 12 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.

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 requires 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.

The Coal Industry

Background. . Coal is mined globally using various methods of surface and underground recovery. Coal is used primarily for the production 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 exceeds 7.0 billion metric tons 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 2016 according to the Chinese Bureau of Statistics. The United States and India follow China with total coal production of over 600 million metric tons in 2016 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, 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, Kentucky and West Virginia. Metallurgical coal is produced at operations in West Virginia and Kentucky. 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.

The majority 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. We shipped to 35 states and 19 countries. During the year, we supplied coal to 117 domestic and 27 foreign customers. In 2016, approximately 92% of our coal sales volume was sold as a thermal product with the remaining 8% as metallurgical.

Coal was used to produce approximately 31% of the electric power generated in the U.S. in 2016 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 2016. We also exported 7% of our production to customers outside the U.S. in 2016.

We rank among the largest metallurgical coal producers in the U.S. Based on internal estimates, we produced close to 10% of total U.S. metallurgical coal in 2016. Our metallurgical coal was sold to six domestic customers and shipped to 16 international destinations in 2016.

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 with other coal producers and traders/brokers 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, 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 200 billion short tons of 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 150 years.

Coal is mined from coal fields 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 declined by an estimated 170 million tons in 2016, to 726 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 declined from an estimated 507 million short tons in 2015 to 407 million short tons in 2016. 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 8,000 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 high 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 fell from 222 million short tons in 2015 to 183 million short tons in 2016. Appalachian coal is located near the prolific eastern shale-gas producing regions. Central Appalachian thermal coal is further disadvantaged for power generation because of the depletion of economically attractive reserves, permitting issues and increasing costs of production. However, 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.

Coal mined from this region generally has a high heat value ranging from 11,400 to 13,200 Btu and a sulfur content ranging from 0.2% to 2.0%. Northern Appalachia includes Maryland, Ohio, Pennsylvania and northern West Virginia. 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%. 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%.

The Interior region includes the Illinois Basin, 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 fell from 168 million short tons in 2015 to approximately 150 million short tons in 2016. 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.

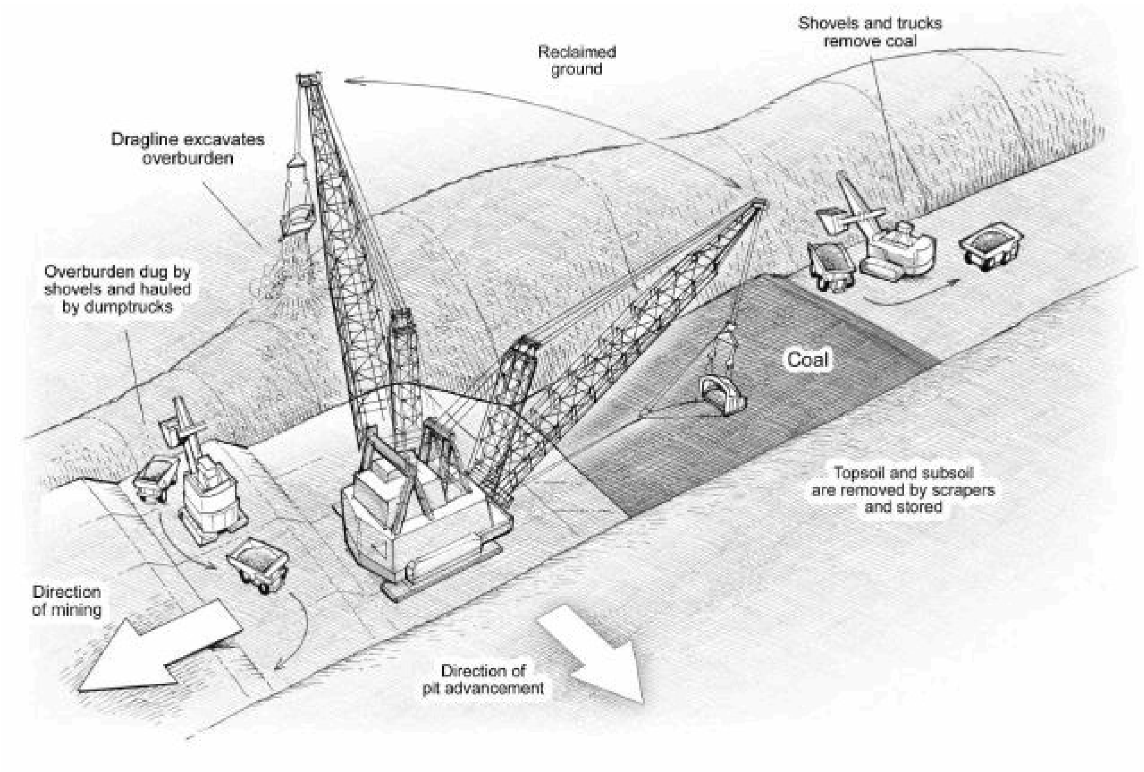
Coal Mining Methods

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

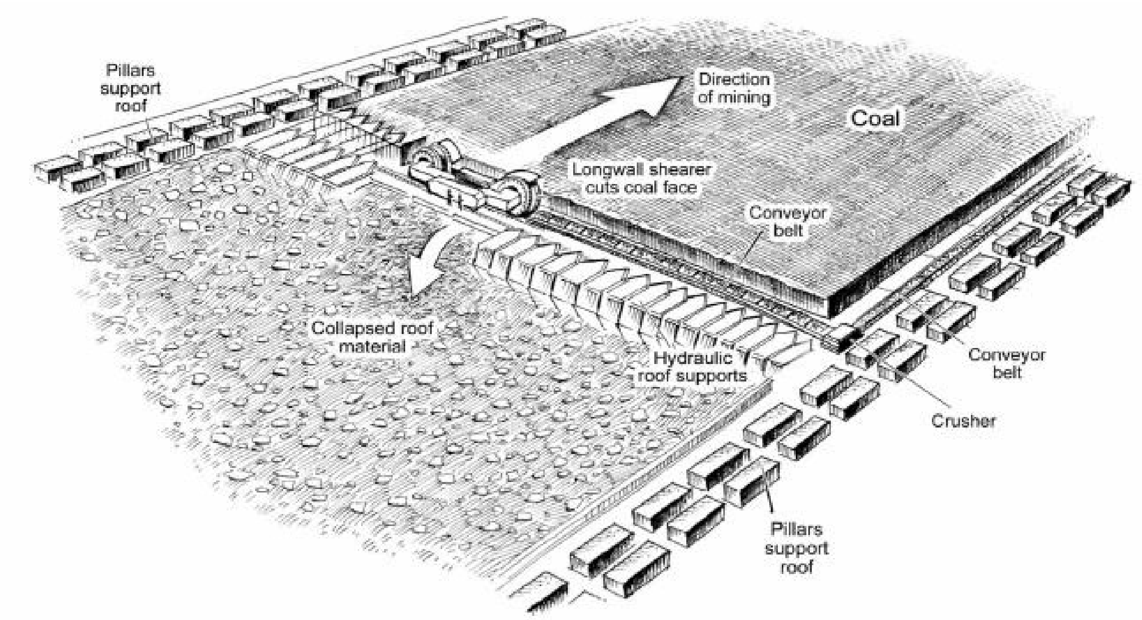
The following diagram illustrates a typical dragline surface mining operation:



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."

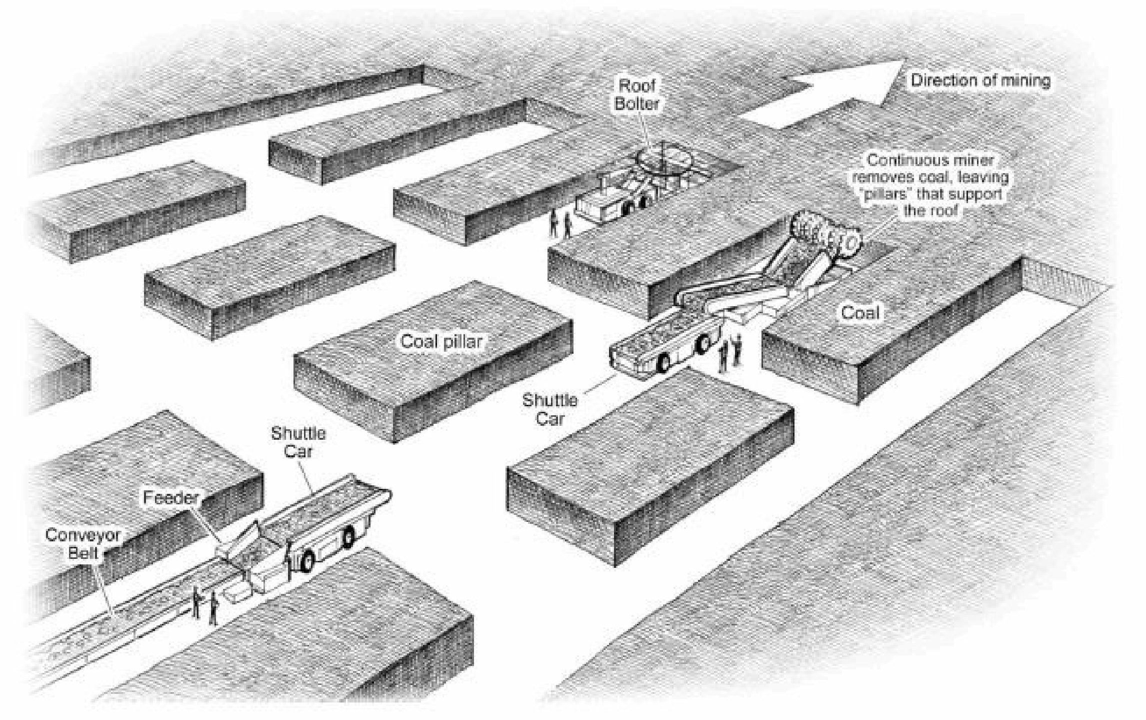
Our underground mines are typically operated using one or both of two different mining techniques: longwall mining and room-and-pillar mining.

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.

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. The majority 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" below.

Our Mining Operations

General. At December 31, 2016, we operated 12 active mines in the United States. The Company's reportable business segments are based on two distinct lines of business, metallurgical and thermal, and may include a number of mine complexes. The Company manages its 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. 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 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. The Company used Adjusted EBITDAR to measure the operating performance of its segments and allocate resources to the segments. Furthermore, analogous measures are used by industry analysts to evaluate the Company's operating performance. Investors should be aware that the Company's presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies. The Company's reportable segments are the Powder River Basin (PRB) segment containing the Company's primary thermal operations in Wyoming; the Metallurgical (MET) segment, containing the Company's metallurgical operations in West Virginia, Kentucky, and Virginia, and the Other Thermal segment containing the Company's 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 periods October 2 through December 31, 2016, January 1 through October 1, 2016 and the years ended December 31, 2015 and 2014, see Note 25 of the 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 a substantial portion 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.

The following table provides a summary of information regarding our active mining complexes as of December 31, 2016, including the total sales associated with these complexes for the periods October 2 through December 31, 2016, January 1 through October 1, 2016 and for the years December 31, 2015 and 2014, and the total reserves associated with these complexes at December 31, 2016. 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.

				Tons Sold[2][3]					
				Predecessor			Successor		
Mining Complex	Captive Mines[1]	Mining Equipment	Railroad	2014	2015	Jan1-Oct1, 2016	Oct2-Dec31, 2016	Total Cost of Property, Plant and Equipment at December 31, 2016	Total Assigned Recoverable Reserves
					(Million tons)			($ millions)	(Million tons)
Powder River Basin:									
Black Thunder	S	D, S	UP/BN	101.2	99.5	49.0	18.9	$ 263.8	968.5
Coal Creek	S	D, S	UP/BN	9.4	7.8	5.5	2.7	43.1	146.0
Metallurgical:									
Lone Mountain	U(3)	CM	NS/CSX	1.9	1.6	0.9	0.4	14.4	9.5
Mountain Laurel	U	LW, CM	CSX	1.7	2.0	1.2	0.4	24.0	13.2
Beckley	U	CM	CSX	1.0	0.9	0.7	0.3	34.9	24.5
Sentinel	U	CM	CSX	1.1	0.9	0.8	0.3	26.9	9.8
Leer	U	LW, CM	CSX	2.7	2.9	3.1	1.0	200.7	38.3
Other Thermal:									
West Elk	U	LW, CM	UP	6.5	5.1	2.4	1.6	31.7	56.2
Viper	U	CM	—	2.2	2.1	1.3	0.3	20.5	38.3
Coal-Mac	S	L, E	NS/CSX	2.8	2.4	1.5	0.5	30.2	23.0
Totals				130.5	125.2	66.4	26.4	$ 690.2	1,327.3

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	
	HW = Highwall miner	

(1) Amounts in parentheses indicate the number of captive mines, if more than one, at the mining complex as of December 31, 2016. Captive mines are mines that we own and operate on land owned or leased by us.

(2) 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.

(3) 2014 tons sold numbers do not include tons of coal sold from the Hazard mining complex, which was sold in 2014, or tons of coal sold from the Cumberland River mining complex, which was idled in 2014. We sold 0.8 million tons of coal from these two mining complexes in 2014.

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 968.5 million tons of proven and probable reserves at December 31, 2016. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of 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 active pit areas and three 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 146.0 million tons of proven and probable reserves at December 31, 2016. The air quality permit for the Coal Creek mine allows for the mining of coal at a rate of 50 million tons per year.

The Coal Creek complex currently consists of active pit areas 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

Lone Mountain. Lone Mountain is an underground mining complex located on approximately 54,000 acres in Harlan County, Kentucky and Lee County, Virginia. The Lone Mountain mining complex extracts PCI and high-quality thermal coal from the Kellioka, Darby and Owl seams.

We control a significant portion of the coal reserves through private leases. The Lone Mountain mining complex had approximately 9.5 million tons of proven and probable reserves at December 31, 2016.

The complex currently consists of three underground mines operating a total of six continuous miner sections. We process coal through a 1,200-ton-per-hour preparation plant. We then ship the coal to our customers via the Norfolk Southern or CSX railroad.

Mountain Laurel. Mountain Laurel is an underground and surface 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 and thermal coal from the Cedar Grove and Alma seams. The Mountain Laurel mining complex has approximately 13.2 million tons of proven and probable reserves at December 31, 2016.

The complex currently consists of one underground mine operating a longwall and three continuous miner sections, a preparation plant and a loadout facility. We process most of the coal through a 2,100-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 19,500 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 24.5 million tons of proven and probable reserves at December 31, 2016.

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 25,500 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 9.8 million tons of proven and probable reserves at December 31, 2016.

Leer. The Leer Complex, located in Taylor County, West Virginia, includes approximately 38.3 million tons of coal reserves as of December 31, 2016 and has primarily High-vol A metallurgical quality coal in the Lower Kittanning seam, and is part of approximately 78,700 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.

Other Thermal

West Elk. West Elk is an underground mining complex located on approximately 17,800 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 56.2 million tons of proven and probable reserves at December 31, 2016.

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 46,100 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, 2016, we had approximately 38.3 million tons of proven and probable reserves.

Coal-Mac. The surface mining complex is located on approximately 46,000 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 23.0 million tons of proven and probable reserves at December 31, 2016.

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. We also have sales personnel 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, 2016, we derived approximately 15% of our total coal revenues from sales to our three largest customers, Southern Company, U.S. Steel Canada Inc. and Tennessee Valley Authority and approximately 42% of our total coal revenues from sales to our 10 largest customers.

In 2016, we sold coal to domestic customers located in 35 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 2016 we also exported coal to Europe, Asia, North America (outside the United States) and South America. Exports to foreign countries were $0.5 billion, $0.4 billion and $0.6 billion for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016 and 2015, trade receivables related to metallurgical-quality coal sales totaled $88.0 million and $32.8 million, respectively, or 48% and 28% 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 foreign revenues by coal shipment destination for the year ended December 31, 2016, were as follows:

(In thousands)		
Europe	$	175,296
Asia		124,170
Central and South America		55,085
North America		100,425
Brokered Sales		—
Total	$	454,976

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 2016, we sold approximately 76% 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, 2016, the average volume-weighted remaining term of our long-term contracts was approximately 2.00 years, with remaining terms ranging from one to five years. At December 31, 2016, remaining tons under long-term supply agreements, including those subject to price re-opener or extension provisions, were approximately 119 million tons.

We typically sell coal to 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. 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 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 terminate the contract. 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 result 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, 2016.

Transportation. We ship our coal to domestic customers by means of railcars, barges, vessels 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 vessel.

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. We generally transport coal produced at our

Appalachian mining complexes via the 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 21.875% 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.

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 Contura Energy, Coronado Coal LLC, Cloud Peak Energy, CONSOL Energy Inc. and Peabody Energy Corp. 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, 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 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.

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.

In 1999, a federal court in West Virginia ruled that the stream buffer zone rule issued under SMCRA prohibited most excess spoil fills. While the decision was later reversed on jurisdictional grounds, the extent to which the rule applied to fills was left unaddressed. On December 12, 2008, OSM finalized a rulemaking regarding the interpretation of the stream buffer zone provisions of SMCRA which confirmed that excess spoil from mining and refuse from coal preparation could be placed in permitted areas of a mine site that constitute waters of the United States. That rule, however, was subject to a challenge in federal court. In addition, on November 30, 2009, OSM announced that it would re-examine and reinterpret the regulations finalized eleven months earlier. On February 20, 2014, the federal court vacated the 2008 rule. On December 22, 2014, OSM published the final revisions to the stream buffer zone rule in the Federal Register. The revisions reinstated the previous version of the rule, but did not announce a new interpretation of the rule regarding the ability to construct excess spoil fills. On December 19, 2016, OSM finalized the "Stream Protection Rule," a re-written version of the stream buffer zone rule which would have required coal operators to restrict mining within 100 feet of waterways. The rule would have also required states to impose additional information gathering and monitoring at and around coal mining sties and would have mandated new financial assurance and reclamation requirements. This rule could have restricted coal producers' ability to develop new mines, or could have required coal producers to modify existing operations, curtailing surface mine operations in and near streams, especially in Appalachia. However, on February 2, 2017, Congress voted to repeal the stream protection rule under the Congressional Review Act. President Trump signed the bill repealing the rule on February 16, 2017.

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.

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 a fee on all coal produced. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA's adoption in 1977. 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 2016, we recorded $23.6 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.

The costs of these bonds have 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, 2016, we posted an aggregate of approximately $528.3 million in surety bonds for reclamation purposes and secured $54.7 million in letters of credit and cash for reclamation bonding obligations. In addition, we had approximately $199.2 million of surety bonds, cash and letters of credit outstanding at December 31, 2016 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 2016, we recorded $47.6 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. Continued tightening of the already stringent regulation of emissions is likely, 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 on additional emissions, such as greenhouse gases (GHG's), from new, modified, reconstructed and existing electric generating units, including coal-fired plants. Other GHG regulations apply to industrial boilers (see discussion of Climate Change, below). These regulations 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). 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. The new standard is subject to pending judicial challenge and potential legislative action, with at least one bill introduced to delay the implementation deadline.

- *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.

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 U.S. Court of Appeals for the District of Columbia Circuit disagreed with the EPA's reading of the Clean Air Act and vacated CAIR in its entirety. In December 2008, the U.S. Court of Appeals for the District of Columbia 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 Federal Court of Appeals for the District of Columbia 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 District of Columbia Circuit decision, remanding the case back to the District of Columbia 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 District of Columbia 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 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. If upheld, it is likely the CSAPR update will increase the pressure to install controls or shut down units, which may further adversely affect the demand for coal.

- *Mercury.* In February 2008, the U.S. Court of Appeals for the District of Columbia 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 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 recently 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. Hence, MATS will likely continue to impact coal-fueled generation as discussed above for at least the near term, and possibly well into the future.

- *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 Court of Appeals 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 have intervened *(Utility Air Regulatory Group v. EPA. D.C. Cir 12-1342, 8/6/2012*).

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 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.

- *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 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 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 from greenhouse gases. For example, in December 2015, representatives of 195 nations reached a landmark 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 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. If the Supreme Court does decide to hear the case, then the stay would remain in effect until the Supreme Court rules. If the Clean Power Plan ultimately is upheld in its current form and is not revoked or revised by the current U.S. Presidential Administration, it is projected to significantly curtail the construction of new coal-fired power plants and have a materially adverse impact on the demand for coal nationally.

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. Oral arguments in this case are scheduled for April 2017. Should the EPA’s regulations be upheld by the court, they could materially impact the ability of customers to build new, or modify or reconstruct existing, coal-fired power plants, and thus reduce the demand for coal.

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 presently-stayed Clean Power Plan (or a comparable alternative) is implemented. The Trump Administration reportedly is evaluating the United States’ continued participation in 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 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.

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 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.

  The use of nationwide permits to authorize stream impacts from mining activities has been the subject of significant litigation. Refer to Item 3, "Legal Proceedings," for more information about certain litigation pertaining to our permits.

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. 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 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, 2016, we employed approximately 4,025 full and part-time employees. We believe that our relations with employees are good.

Executive Officers of the Registrant

The following is a list of our executive officers, their ages as of February 24, 2017 and their positions and offices during the last five years:

Name	Age	Position
Kenneth D. Cochran	56	Mr. Cochran has served as our Senior Vice President-Operations since August 2012. From May 2011 to August 2012, Mr. Cochran served as Group President of our western operations, which included Thunder Basin Coal Company, the Arch Western Bituminous Group, Arch of Wyoming and the Otter Creek development, and served as President and General Manager of Thunder Basin Coal Company from 2005 to April 2011. Prior to joining Arch Coal in 2005, Mr. Cochran spent 20 years with TXU Corporation. Mr. Cochran currently serves on the boards of Knight Hawk Holdings, LLC, and Tongue River Holding Company.
John T. Drexler	47	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	59	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 and the National Mining Association. Mr. Eaves was previously a director of Advanced Emissions Solutions, Inc. and former chairman of the National Coal Council.
Robert G. Jones	60	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.
Allen R. Kelley	56	Mr. Kelley was appointed Vice President-Human Resources in March 2014. From 2008 to March 2014, Mr. Kelley served as our Vice President-Enterprise Risk Management. From 2005 to 2008, Mr. Kelley served as our Director of Internal Audit. Prior to 2005, Mr. Kelley held various finance and accounting positions within the corporate and operations functions of Arch Coal, Inc.
Paul A. Lang	56	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 Advanced Emissions Solutions, Inc. and Knight Hawk Holdings, LLC. Mr. Lang also serves 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 S. Slone	53	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 immediate past co-chair of the Coal Utilization Research Council, the chair of the Coal Policy Committee of the National Coal Council, and a member of the steering committee of the Consortium for Clean Coal Utilization at Washington University in St. Louis.
John A. Ziegler, Jr.	50	Mr. Ziegler was appointed Chief Commercial Officer in 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.

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*. You may also read and copy any document we file at the SEC's Public Reference Room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

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.

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.
Brown coal	Coal of gross calorific value of less than 5700 kilocalories per kilogramme (kcal/kg), which includes lignite and sub-bituminous coal where lignite has a gross calorific value of less than 4165 kcal/kg and sub-bituminous coal has a gross calorific value between 4165 kcal/kg and 5700 kcal/kg.
Btu	A measure of the energy required to raise the temperature of one pound of water one degree of Fahrenheit.
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.
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.
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.
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.
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.

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 and 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 will not be 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 be 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 will 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. Adjustments to the carrying amounts could be material and could 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 prior periods. Our Annual Report on Form 10-K for the fiscal year ending December 31, 2016 reflects the consummation of the Plan and the adoption of fresh start accounting effective October 1, 2016.

Our emergence from bankruptcy will reduce or eliminate our net operating losses and other tax attributes and limit our ability to offset future taxable income with tax losses and credits incurred prior to its emergence from bankruptcy.

The use of 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 the Effective Date of the Plan ("the Emergence Ownership Change"). The limitation resulting from the Initial Ownership Change is substantial and applies to all NOLs and tax AMT credits existing at the time of the Initial Ownership Change. The limitation resulting from the Emergence Ownership Change will have a significant impact on our ability to offset future taxable income with carryforward net operating losses, AMT tax credits and an overall limitation of certain tax deductions. NOLs and AMT credits generated after the Emergence Ownership Change are generally not subject to the limitations from the prior ownership changes. As a result of the discharge of debt in the Chapter 11 Cases, we and our subsidiaries will be required to reduce the amount of their NOLs and AMT credits and potentially other tax attributes existing at the end of our taxable year.

Risks Related to Our Operations

Coal prices are subject to change based on a number of factors and coal prices have recently experienced an historic level of depression. 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 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.

Due to a number of factors outside our control, including decelerating demand for coal used in electricity (due to low natural gas prices and regulations), an oversupplied market and increased competition particularly from non-U.S. suppliers taking advantage of a strong dollar, we have recently experienced a sustained and significant downturn in coal pricing over the last several years. Pricing may be adversely affected or we may need to reduce production as a result of our uncommitted volume levels. If there is a further decline in the prices we receive for our future coal sales contracts, it could materially and adversely affect us by decreasing our profitability, cash flows, liquidity and the value of our coal reserves.

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 over 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 security prices, severely limited liquidity and credit availability, and resulted in declining valuations of assets. If there are downturns in economic conditions, our customers' and our businesses, financial conditions or 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. During unfavorable economic conditions we are focused on cost control and capital discipline, but there can be no assurance that these actions, 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.

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 China have, and could further, materially reduce coal prices and therefore materially reduce our revenues and profitability. Potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We cannot assure you that we will be able to compete on the basis of price or other factors with companies that in the future may 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 to increase 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. We cannot assure you that the result of current or further consolidation in the coal industry or current or future bankruptcy proceedings of our coal competitors will not 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 affect 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.

Any change 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 2016. 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 for power generation and governmental regulations. Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand and can be caused 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 needed 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 is seen as having a lower environmental impact than coal-fueled generation. 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 mining complex, which accounted for approximately 72% of the coal volume we sold in 2016, our coal mining operations may be disrupted and we could experience a delay or halt of production or shipments or our operating costs could 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 acquire additional 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, or 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.

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. The delay in the LBA process caused by the 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.

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 more unfavorable 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 state and federal 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. In situations where we have chosen to concentrate a large portion of purchases with one supplier, it has been to take advantage of cost savings from larger volumes of purchases and to ensure security of supply. If the 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.

Disruptions in the quantities of coal produced by our contract mine operators or purchased from other third parties could temporarily impair our ability to fill customer orders or increase our operating costs.

We use independent contractors to mine coal at certain of our mining complexes, including select operations in our Appalachian segment. In addition, we purchase coal from third parties that we sell to our customers. Operational difficulties at contractor-operated mines or mines operated by third parties from whom we purchase coal, changes in demand for contract miners from other coal producers and other factors beyond our control could affect the availability, pricing, and quality of coal produced for or purchased by us. Disruptions in the quantities of coal produced for or purchased by us could impair our ability to fill our customer orders or require us to purchase coal from other sources in order to satisfy those orders. If we are unable to fill a customer order or if we are required to purchase coal from other sources in order to satisfy a customer order, we could lose existing customers and our operating costs could increase.

Our profitability depends upon the long-term 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 long-term 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 long-term coal supply agreements or 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 the Clean Air Act, could deter our customers from entering into long-term 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 long-term coal supply agreements typically contain *force majeure* provisions allowing the parties to temporarily suspend performance during specified events beyond their control. Most of our long-term 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 long-term coal supply agreements could result in negative economic consequences to us, including price adjustments, purchasing 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 long-term 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 effected 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.

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 regulatory and permit requirements, environmental and other legal challenges, public perceptions and resulting political pressures, operational issues at terminals and competition among domestic coal producers for access to limited terminal capacity, among other factors. 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, 2016, we derived approximately 15% of our total coal revenues from sales to our three largest customers and approximately 42% 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, was 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. While we employ a variety of risk monitoring and mitigation techniques, those 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 are selling our coal to new customers and customers in new countries, whose business practices and reputations are not as well known to us. We are also challenged by political risks by expanding internationally, including the potential for expropriation of assets and limits 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 may be subject to security breaches which could result in unauthorized access to our facilities or to information we are trying to protect. Unauthorized physical access to one or more of our facilities or locations, or electronic access to our proprietary or confidential information 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 for damages related to the theft or misuse of such information, any of which could have a substantial impact on our results of operations, financial condition or cash flow.

Our ability to operate the Company effectively could be impaired if we lose key personnel or fail to attract qualified personnel.

We manage our business with a number of key personnel, the loss of whom could have a material adverse effect on us, absent the completion of an orderly transition. In addition, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled and qualified personnel, particularly personnel with mining experience. We cannot provide assurance that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

We may be unable to comply with the restriction imposed by our New First Lien 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 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 New First Lien Debt Facility contains customary affirmative and negative covenants, which include restrictions on (i) indebtedness, (ii) liens and guarantees, (iii) liquidations, mergers, consolidations, 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) payment of other indebtedness, (x) no restriction in agreements on dividends or certain loans, (xi) loans and investments, (ix) transactions with respect to Bonding Subsidiaries and (xiii) changes in organizational documents. 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 New First Lien Debt Facility.

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 oxides, 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 is in the process of being developed and implemented. The Clean Power Plan, under review by U.S. courts, would severely limit emissions of carbon dioxide which would adversely affect our ability to sell coal. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

Considerable uncertainty is associated with these air emissions initiatives. The content of regulatory requirements in the United States continues to evolve and develop and many new regulatory initiatives remain subject to review by federal or state agencies or the courts. Stringent air emissions limitations are either in place or are likely to be imposed in the short to medium term, and these limitations will likely 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 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 global climate issues. 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, a set of regulations promulgated by the EPA currently under review by U.S. courts would severely limit emissions of carbon dioxide which would adversely affect our ability to sell coal. 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. Enactment of laws or passage of regulations regarding greenhouse 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, certain banks and other financing sources have taken actions to limit available financing for the development of new coal-fueled power plants, 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. Those 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, 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 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 or the extension of time for delivery or terminate 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. We cannot assure you that we have been or will be at all times in compliance with the applicable laws and regulations. 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. Such changes could have a material adverse effect on our financial condition and results of operations. You should see the section entitled "Environmental and Other Regulatory Matters" in Item 1 for more information about the various governmental regulations affecting us.

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 or if governmental regulations change significantly. We are required to record new obligations as liabilities at fair value under generally accepted accounting principles. 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 the 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. The matter is pending before the U.S. District Court for the Southern District of West Virginia on our subsididary's motion for summary judgment. If the matter is resolved ultimately in a manner that is adverse to the interests of our operating subsidiaries, such subsidiaries' operating results may be adversely impacted. For more information regarding this litigation matter you should see the section entitled "Legal Proceedings—Permit Litigation Matters" under Item 3.

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. 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 lease by application programs; costs associated with providing healthcare benefits to employees; health and safety standards; accounting standards; taxation requirements; and competition laws.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our Properties

At December 31, 2016, we owned or controlled, primarily through long-term leases, approximately 28,315 acres of coal land in Ohio, 1,060 acres of coal land in Maryland, 46,542 acres of coal land in Virginia, 355,205 acres of coal land in West Virginia, 103,733 acres of coal land in Wyoming, 274,273 acres of coal land in Illinois, 85,459 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 18,443 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 84,958 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 2.1 billion tons of proven and probable recoverable reserves at December 31, 2016. Our coal reserve estimates at December 31, 2016 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.”

The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2016:

Total Assigned Reserves
(Tons in millions)

	Total Assigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btus per lb. (1)	Reserve Control		Mining Method		Past Reserve Estimates	
				<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Under-ground	2014	2015
Wyoming	1,115	1,109	6	1,047	68	—	8,831	1,115		1,115	—	1,423	1,318
Colorado	56	51	5	56	—	—	11,500	56	—	—	56	65	53
Central App.	70	64	6	30	40	—	13,055	68	2	23	47	139	35
Northern App.	48	43	5	—	47	1	13,011	10	38	—	48	74	40
Illinois	38	23	15	—	—	38	10,730	32	6	—	38	33	37
Total	1,327	1,290	37	1,133	155	39	9,374	1,281	46	1,138	189	1,734	1,483

(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	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btus per lb.(1)	Reserve Control		Mining Method	
				<1.2	1.2-2.5	>2.5		Leased	Owned	Surface	Under-ground
Wyoming	285	239	46	237	48	—	8,457	285	—	285	—
Colorado	28	22	6	28	—	—	11,217	28	—	—	28
Central App.	58	49	9	20	25	13	12,530	11	47	40	18
Northern App.	169	92	77	—	168	1	13,000	8	161	—	169
Illinois	282	187	95	—	—	282	11,170	57	225	4	278
Total	822	589	233	285	241	296	10,704	389	433	329	493

(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 66% 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 8% 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, 2016 was $0.4 billion, consisting of $2.3 million of prepaid royalties and a net book value of coal lands and mineral rights of $0.4 billion.

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. You should see 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.

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. The review could take the form of a programmatic environmental impact statement, which allows a broader look at all aspects of federal coal leasing across regions and can incorporate environmental and health impacts as well as financial ones. The last review on this scale occurred in the 1980's. 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, 2016, approximately 22% 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 58,758 acres of property to other coal operators in 2016. We received royalty income of $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, $6.3 million in 2015 from the mining of approximately 2.1 million tons and $9.6 million in 2014 from the mining of approximately 2.6 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.

In addition to the following matters, 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.

Permit Litigation Matters

Surface mines at our Mingo Logan and Coal-Mac mining operations were identified in an existing lawsuit brought by the Ohio Valley Environmental Coalition (OVEC) in the U.S. District Court for the Southern District of West Virginia as having been granted Clean Water Act § 404 permits by the Army Corps of Engineers (Corps), allegedly in violation of the Clean Water Act and the National Environmental Policy Act. The lawsuit, brought by OVEC in September 2005, originally was filed against the Corps for permits it had issued to four subsidiaries of a company unrelated to us or our operating subsidiaries. The suit claimed that the Corps had issued permits to the subsidiaries of the unrelated company that did not comply with the National Environmental Policy Act and violated the Clean Water Act.

The court ruled on the claims associated with those four permits in orders of March 23 and June 13, 2007. In the first of those orders, the court rescinded the four permits, finding that the Corps had inadequately assessed the likely impact of valley fills on headwater streams and had relied on inadequate or unproven mitigation to offset those impacts. In the second order, the court entered a declaratory judgment that discharges of sediment from the valley fills into sediment control ponds constructed in-stream to control that sediment must themselves be permitted under a different provision of the Clean Water Act, § 402, and meet the effluent limits imposed on discharges from these ponds. Both of the district court rulings were appealed to the U.S. Court of Appeals for the Fourth Circuit.

Before the court entered its first order, the plaintiffs were permitted to amend their complaint to challenge the Coal-Mac and Mingo Logan permits. Plaintiffs sought preliminary injunctions against both operations, but later reached agreements with our operating subsidiaries that have allowed mining to progress in limited areas while the district court's rulings were on appeal. The claims against Coal-Mac were thereafter dismissed.

In February 2009, the Fourth Circuit reversed the district court. The Fourth Circuit held that the Corps' jurisdiction under Section 404 of the Clean Water Act is limited to the narrow issue of the filling of jurisdictional waters. The court also held that the Corps' findings of no significant impact under the National Environmental Policy Act and no significant degradation under the Clean Water Act are entitled to deference. Such findings entitle the Corps to avoid preparing an environmental impact statement, the absence of which was one issue on appeal. These holdings also validated the type of mitigation projects proposed by our operations to minimize impacts and comply with the relevant statutes. Finally, the Fourth Circuit found that stream segments, together with the sediment ponds to which they connect, are unitary "waste treatment systems," not "waters of the United States," and that the Corps had not exceeded its authority in permitting them.

OVEC sought rehearing before the entire appellate court, which was denied in May 2009, and the decision was given legal effect in June 2009. An appeal to the U.S. Supreme Court was then filed in August 2009. On August 3, 2010 OVEC withdrew its appeal.

Mingo Logan filed a motion for summary judgment with the district court in July 2009, asking that judgment be entered in its favor because no outstanding legal issues remained for decision as a result of the Fourth Circuit's February 2009 decision. By a series of motions, the United States obtained extensions and stays of the obligation to respond to the motion in the wake of its letters to the Corps dated September 3 and October 16, 2009 (discussed below). By order dated April 22, 2010, the district court stayed the case as to Mingo Logan for the shorter of either six months or the completion of the U.S. Environmental Protection Agency's (EPA) proposed action to deny Mingo Logan the right to use its Corps' permit (as discussed below).

On October 15, 2010, the United States moved to extend the existing stay for an additional 120 days (until February 22, 2011) while the EPA Administrator reviewed the "Recommended Determination" issued by the EPA Region 3. By Memorandum Opinion and Order dated November 2, 2010, the court granted the United States' motion. On January 13, 2011, the EPA issued its "Final Determination" to withdraw the specification of two of the three watersheds as a disposal site for dredged or fill material approved under the current Section 404 permit. The court was notified of the Final Determination and by order dated March 21, 2011 stayed further proceedings in the case until further order of the court, in light of the challenge to the EPA's "Final Determination" then pending in federal court in Washington, D.C. A full account and status of this litigation surrounding the Final Determination is set forth in the immediately following section.

On April 5, 2012, Mingo Logan moved to lift the stay referenced above. On June 5, 2012, the court entered an order lifting the stay and allowing the case to proceed on Mingo Logan's Motion for Summary Judgment. Shortly thereafter, OVEC filed a motion for leave to file a seventh amended and supplemental complaint seeking to update existing counts and raising two new claims (one, to enforce the EPA's "Final Determination" and, the other, that the Corps' refusal to prepare a Supplemental Environmental Impact Statement violates the APA and NEPA). By Memorandum, Opinion and Order dated July 25, 2012, the court granted OVEC's motion and directed the Clerk to file OVEC's Seventh Amended and Supplemental Complaint. Mingo Logan filed its Motion for Summary Judgment on August 31, 2012, along with its Answer to the Seventh Amended and Supplemental Complaint and the matter remains pending before the court.

EPA Actions Related to Water Discharges from the Spruce Permit

By letter of September 3, 2009, the EPA asked the Corps of Engineers to suspend, revoke or modify the existing permit it issued in January 2007 to Mingo Logan under Section 404 of the Clean Water Act, claiming that "new information and circumstances have arisen which justify reconsideration of the permit." By letter of September 30, 2009, the Corps of Engineers advised the EPA that it would not reconsider its decision to issue the permit. By letter of October 16, 2009, the EPA advised the Corps that it has "reason to believe" that the Mingo Logan mine will have "unacceptable adverse impacts to fish and wildlife resources" and that it intends to issue a public notice of a proposed determination to restrict or prohibit discharges of fill material that already are approved by the Corps' permit. By federal register publication dated April 2, 2010, the EPA issued its "Proposed Determination to Prohibit, Restrict or Deny the Specification, or the Use for Specification of an Area as a Disposal Site: Spruce No. 1 Surface Mine, Logan County, WV" pursuant to Section 404(c) of the Clean Water Act, the EPA accepted written comments on its proposed action (sometimes known as a "veto proceeding"), through June 4, 2010 and conducted a public hearing, as well, on May 18, 2010. We submitted comments on the action during this period. On September 24, 2010, the EPA Region 3 issued a "Recommended Determination" to the EPA Administrator recommending that the EPA prohibit the placement of fill material in two of the three watersheds for which filling is approved under the current

Section 404 permit. Mingo Logan, along with the Corps, West Virginia DEP and the mineral owner, engaged in a consultation with the EPA as required by the regulations, to discuss “corrective action” to address the “unacceptable adverse effects” identified. On January 13, 2011, the EPA issued its “Final Determination” pursuant to Section 404(c) of the Clean Water Act to withdraw the specification of two of the three watersheds approved in the current Section 404 permit as a disposal site for dredged or fill material. By separate action, Mingo Logan sued the EPA on April 2, 2010 in federal court in Washington, D.C. seeking a ruling that the EPA has no authority under the Clean Water Act to veto a previously issued permit (Mingo Logan Coal Company, Inc. v. USEPA, No. 1:10-cv-00541(D.D.C.)). The EPA moved to dismiss that action, and we responded to that motion.

Pursuant to a scheduling order for summary disposition of the case, motions and cross-motions for summary judgment by both parties were filed. On November 30, 2011, the court heard arguments from the parties limited only to the threshold issue of whether the EPA had the authority under Section 404(c) of the Clean Water Act to withdraw the specification of the disposal site after the Corps had already issued a permit under Section 404(a). The court deferred consideration of the remaining issue (i.e. whether the EPA’s “Final Determination” is otherwise lawful) until after consideration of the threshold issue. On March 23, 2012, the court entered an Order and a Memorandum Opinion granting Mingo Logan’s motion for summary judgment, denying the EPA’s cross-motion for summary judgment, vacating the Final Determination and ordering that Mingo Logan’s Section 404 permit remains valid and in full force.

On May 11, 2012, the EPA filed a notice of appeal to the United States Court of Appeals for the District of Columbia Circuit. The court heard oral arguments on March 14, 2013. By opinion of the court filed on April 23, 2013, the court reversed the district court on the threshold issue and remanded the matter to the district court to address the merits of our APA challenge to the Final Determination. On June 6, 2013, Mingo Logan filed a Petition for Rehearing En Banc and by Order filed July 25, 2013, the court denied the petition.

On November 13, 2013, Mingo Logan filed a Petition for Writ of Certiorari with the Supreme Court of the United States seeking review of the D.C. Circuit’s decision. On March 24, 2014, the Supreme Court denied Mingo Logan’s Petition for Writ of Certiorari and remanded the matter to the federal district court for the District of Columbia for further consideration on the merits of the Final Determination. On September 30, 2014, the court entered an opinion and order denying Mingo Logan’s motion for summary judgment and granting the government’s motion for summary judgment. The court upheld the Final Determination finding that EPA’s decision to withdraw the specifications for filling in Oldhouse Branch and Pigeonroost Branch under Mingo Logan’s Section 404 permit was not arbitrary and capricious. On November 11, 2014, Mingo Logan filed a notice of appeal to the United States Court of Appeals for the District of Columbia Circuit. The court heard oral arguments on April 11, 2016. By opinion of the court filed on July 19, 2016, the court affirmed the district court judgment thus upholding the EPA’s Final Determination.

UMWA 1974 Pension Plan et al. v Peabody Energy and Arch

On July 16, 2015, the UMWA 1974 Pension Trust (“1974 Plan”) and its Trustees filed a Complaint for Declaratory Judgment against Peabody Energy Corporation, Peabody Holding Company, LLC and Arch, in the U.S. District Court in Washington D.C., seeking an order from the court requiring the defendants to submit to arbitration to determine their responsibility for pension withdrawal liability (triggered by Patriot Coal Corporation’s (“Patriot”) bankruptcy filing) for 1974 Plan participants of Patriot who formerly worked for Peabody and Arch subsidiaries. In the alternative, the complaint asks the court to declare that Peabody and Arch are liable for Patriot’s withdrawal liability. With respect to Arch, plaintiffs allege that Arch engaged in actions to avoid and evade pension fund withdrawal liability when it sold subsidiaries that were signatory to UMWA agreements, to Magnum Coal Company (“Magnum”) in 2005, allegedly in violation of ERISA law. Patriot subsequently purchased Magnum in 2008. On October 29, 2015, plaintiffs filed an amended complaint to reflect that Patriot formally rejected its obligations to contribute to the 1974 Plan, triggering a withdrawal. The amended complaint further alleged that Arch owes $299.8 million in withdrawal liability. On October 29, 2015, the 1974 Plan issued a letter to Arch demanding payment of this withdrawal liability amount. Arch notified the District Court and the parties to the litigation of its bankruptcy filing and the automatic stay and, on January 21, 2016, the plaintiffs agreed that the automatic stay in the Chapter 11 Case applies to Arch and its affiliates that have filed bankruptcy petitions. Thereafter, on May 26, 2016, the 1974 Plan filed a proof of claim asserting a $299.0 million claim against Arch and its debtor subsidiaries. On September 9, 2016, Arch and the 1974 Plan entered into a confidential agreement in principle to settle the withdrawal liability dispute, which agreement became effective on November 3, 2016.

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, 2016.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

On the Plan Effective Date, all shares of our old common stock were canceled and 24,589,834 shares of Class A Common Stock and 410,166 shares of Class B Common Stock, par value $.01 per share, were distributed to the secured lenders and to certain holders of general unsecured claims under the Plan. In addition, on the Effective Date, Arch Coal issued Warrants to purchase up to an aggregate of 1,914,856 shares of Class A Common Stock. Arch Coal relied, based on the confirmation order it received from the Bankruptcy Court, on Section 1145(a)(1) of the U.S. Bankruptcy Code to exempt from the registration requirements of the Securities Act of 1933, as amended (i) the offer and sale of Common Stock to the secured lenders and to the general unsecured creditors, (ii) the offer and sale of the Warrants to the holders of claims arising under the Cancelled Notes and (iii) the offer and sale of the Class A Common Stock issuable upon exercise of the Warrants. Section 1145(a)(1) of the Bankruptcy Code exempts the offer and sale of securities under a plan of reorganization from registration under Section 5 of the Securities Act and state laws if three principal requirements are satisfied:

- the securities must be offered and sold under a plan of reorganization and must be securities of the debtor, of an affiliate participating in a joint plan of reorganization with the debtor or of a successor to the debtor under the plan of reorganization;
- the recipients of the securities must hold claims against or interests in the debtor; and
- the securities must be issued in exchange, or principally in exchange, for the recipient's claim against or interest in the debtor.

Our new common stock is listed on the NYSE under the symbol "ARCH" as has been trading since October 5, 2016. No prior established public trading market existed for our new common stock prior to this date. Based upon information provided by our transfer agent, as of February 16, 2017, we had one stockholder of record.

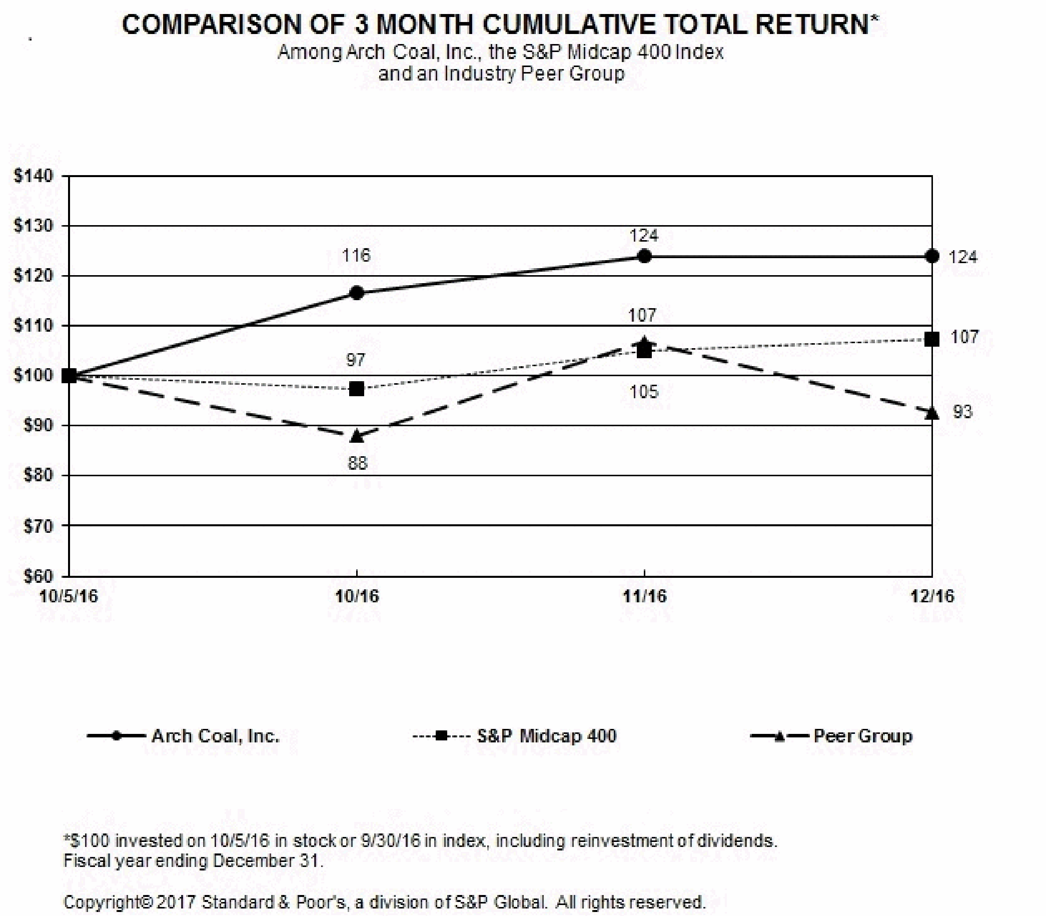
The following table sets forth the per share high and low closing prices for our common stock as reported on the NYSE for the periods presented:

	High	Low
2017:		
First Quarter (through February 16, 2017)	$ 76.05	$ 68.65
2016:		
Fourth Quarter (from October 5, 2016)	$ 85.16	$ 61.31

We have paid no cash dividends on our stock. Any future determination to pay cash dividends will be at the discretion of our Board of Directors, subject to applicable limitations under Delaware law, and will be dependent on our results of operations, financial condition, contractual restrictions and other factors deemed relevant by our Board of Directors.

Stockholder Return Performance Presentation

The following graph compares the cumulative stockholder return from October 5, 2016, the date our common stock began trading following the Plan Effective Date, through December 31, 2016, for our current existing stock, the S&P Midcap 400 index and a customized peer group. Because the value of the Predecessor common stock bears no relation to the value of our existing common stock, the graph below reflects only our current existing common stock. The peer group consists of CONSOL Energy Inc. and Peabody Energy Corp. Peabody Energy Corp. filed for Chapter 11 bankruptcy protection, and its stock traded on the OTC Pink market during the performance period reflected in the graph. Alpha Natural Resources, Inc. is no longer included in our peer group, because the company emerged from Chapter 11 as a privately held company prior to the performance period. The graph tracks the performance of a $100 investment in our current existing common stock, in the peer group, and the index (with the reinvestment of all dividends) from October 5, 2016 through December 31, 2016.



	10/5/2016	10/16	11/16	12/16
Arch Coal, Inc.	100.00	116.48	123.86	123.89
S&P Midcap 400	100.00	97.32	105.12	107.42
Peer Group	100.00	87.96	106.67	92.83

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

ITEM 6. SELECTED FINANCIAL DATA.

(In thousands, except per share data)	Successor October 2 through December 31, 2016	Predecessor January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
Statement of Operations Data:	(1)	(1)	(2)		(3)	(4)
Revenues	$ 575,688	$ 1,398,709	$ 2,573,260	$ 2,937,119	$ 3,014,357	$ 3,768,126
Asset impairment and mine closure costs	—	129,267	2,628,303	24,113	220,879	539,182
Goodwill impairment	—	—	—	—	265,423	330,680
Income (loss) from operations	46,118	(257,138)	(2,865,063)	(149,531)	(663,141)	(757,012)
Interest expense	(11,241)	(135,888)	(397,979)	(390,946)	(381,267)	(317,615)
Non-operating expenses	(759)	1,627,828	(27,910)	—	(42,921)	(23,668)
Income (loss) from continuing operations	33,449	1,242,081	(2,913,142)	(558,353)	(745,228)	(738,915)
Net income (loss) attributable to Arch Coal	33,449	1,242,081	(2,913,142)	(558,353)	(641,832)	(683,955)
Basic earnings (loss) per common share	$ 1.34	$ 58.33	$ (136.86)	$ (26.31)	$ (30.26)	$ (32.36)
Diluted earnings (loss) per common share	$ 1.31	$ 58.28	$ (136.86)	$ (26.31)	$ (30.26)	$ (32.36)
Balance Sheet Data:						
Total assets	$ 2,136,597	$ 2,123,829	$ 5,041,881	$ 8,346,362	$ 8,896,571	$ 9,913,791
Working capital	566,391	522,465	(4,361,009)	1,023,357	1,293,849	1,337,035
Current maturities of debt	11,038	6,662	5,042,353	12,191	14,419	17,557
Long-term debt, less current maturities	351,841	353,272	30,953	5,064,818	5,043,454	5,008,232
Other long-term obligations	725,948	786,015	755,283	695,881	717,174	825,080
Noncurrent deferred income tax liability	—	—	—	422,809	413,546	664,182
Arch Coal stockholders' equity	746,577	687,483	(1,244,289)	1,668,154	2,253,249	2,854,567
Cash Flow Data:						
Cash provided by (used in) operating activities	84,192	(228,218)	(44,367)	(33,582)	55,742	332,804
Depreciation, depletion and amortization, including amortization of sales contracts, net	33,400	190,853	370,534	405,561	438,247	500,319
Capital expenditures	15,214	82,434	119,024	147,286	296,984	395,225
Net proceeds from the issuance of long term debt	—	—	—	(4,519)	623,511	1,942,685
Payments to retire debt, including redemption premium	—	—	—	—	628,660	452,934
Net decrease in borrowings under lines of credit and commercial paper program	—	—	—	—	—	(481,300)
Dividend payments	—	—	—	2,123	25,475	42,440
Operating Data:						
Tons sold	26,812	67,128	127,632	134,360	139,607	140,820
Tons produced	26,619	66,658	126,820	132,614	136,613	135,934
Tons purchased from third parties	193	481	1,287	1,182	2,925	4,327

(1) Our 2016 results were impacted by the filing of bankruptcy, subsequent emergence and the application of fresh start accounting. See Note 3, "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 5 to the Consolidated Financial Statements, "Impairment Charges and Mine Closure Costs."

(3) As part of a strategy to divest non-core thermal coal assets, on August 16, 2013, we sold Canyon Fuel Company, LLC ("Canyon Fuel") to Bowie Resources, LLC for $423 million. Canyon Fuel operated the Sufco and Skyline longwall mining complexes and the Dugout Canyon continuous miner operation in Utah. We recognized a gain on the sale of Canyon Fuel, net of tax, of $77.0 million during the third quarter of 2013.

(4) Our results in 2012 were impacted by challenging market conditions. In response to these conditions, we idled 10 mines in Appalachia and curtailed production at other thermal mines. We incurred $523.6 million of closure and impairment costs relating to the closures, and recognized goodwill impairment charges of $330.7 million. In addition, we refinanced our debt, increasing our average borrowing level to build cash and highly liquid investments on the balance sheet as well as to decrease near-term maturities of debt.

The selected financial information presented above for the period October 2 through December 31, 2016, the period from January 1 through October 1, 2016, and the years ended December 31, 2015, 2014, 2013 and 2012 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 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 Successor period from October 2 through December 31, 2016 were impacted by strengthening of both the thermal and metallurgical coal markets. The domestic thermal market rebounded somewhat from lows in the first half of 2016 as natural gas prices rose. Warmer than normal summer temperatures, increasing natural gas exports, and flat to slightly declining natural gas supply supported natural gas pricing at levels that allowed some thermal coals, particularly Powder River Basin coals, to compete economically for a larger share of electric generation. Additionally, pricing in international thermal coal markets strengthened sufficiently to make some thermal exports economically viable for certain of our operations in the Successor period.

Metallurgical coal markets continued to strengthen substantially through most of the Successor period from October 2 through December 31, 2016, with prompt international pricing reaching multi-year highs as near-term supply shortages became more evident. We believe the supply shortages were driven by: a Chinese mandate to restrict its domestic coal supply; supply rationalization in North America; years of global underinvestment in the industry; and some specific international supply disruptions, particularly in Australia. Although the majority of our metallurgical volume was committed and priced for the Successor period prior to the improvement in pricing, certain index-based and prompt sales reflected the higher prices. Late in the Successor period, prompt metallurgical pricing began to retrace from these highs as the Chinese loosened their supply restrictions and supply disruptions abated. International prompt metallurgical prices remain well above recent lows. We sold 1.9 million tons of metallurgical coal during the Successor period.

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.

On October 5, 2016, Arch Coal satisfied the closing conditions contemplated by the Plan, which became effective on that date (the "Effective Date").

On the plan Effective Date, we applied fresh start accounting which requires 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. 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 further information on fresh start accounting, please see Note 3 to the Consolidated Financial Statements, "Emergence from Bankruptcy and Fresh Start Accounting."

Results of Operations - Successor

Period from October 2 through December 31, 2016

Revenues. Our revenues consist of coal sales.

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.

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
	(In thousands)
Cost of sales (exclusive of items shown separately below)	$ 470,644
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	22,836
Other operating expense (income), net	(5,340)
Total costs, expenses and other	$ 529,570

Cost of sales. Our cost of sales for the period from October 2 through December 31, 2016 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. Our depreciation, depletion and amortization costs for the period from October 2 through December 31, 2016 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. 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. Total selling, general and administrative expenses consist primarily of compensation costs of $15.3 million, and professional services and usage and maintenance agreements of $5.1 million.

Other operating expense (income), net. Other operating expense (income), net consists primarily of miscellaneous revenues including royalties and net gains on asset sales of $5.4 million and net income from equity investments of $1.7 million, partially offset by miscellaneous expenses primarily related to our land company of $2.1 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)
Reorganization income (loss), net	$ (759)

Nonoperating expenses in the current period are related to our reorganization. For further information on our successful reorganization, please see Note 3 to the Consolidated Financial Statements, "Emergence from Bankruptcy and Fresh Start Accounting."

Provision for 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 income taxes	$ 1,156

See further discussion in Note 14, to the Consolidated Financial Statements "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 reorganization items, net. Adjusted EBITDAR may also be adjusted for items that may not reflect the trend of future results. In conjunction with our emergence from bankruptcy, we have added accretion on asset retirement obligations as an adjustment to arrive at Adjusted EBITDAR. 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 continuing coal operations for the Successor 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

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 Successor 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 Successor period from October 2 through December 31, 2016 benefited from the significant increase in international pricing for metallurgical coal. As discussed above, 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 Successor period. Longwall operations accounted for approximately 55% of our shipment volume in the period. Late in the Successor 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 Successor period from October 2 through December 31, 2016 benefited from the increased natural gas pricing discussed in the Powder River Basin segment discussion 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 current period.

Results of Operations - Predecessor

Period from January 1 through October 1, 2016

Revenues. Our revenues consist of coal sales.

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:

	Predecessor
	January 1 through October 1, 2016
	(In thousands)
Cost of sales (exclusive of items shown separately below)	$ 1,264,464
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	59,343
Other operating expense (income), net	(15,257)
Total costs, expenses and other	$ 1,655,847

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 consist primarily of compensation costs of $38.5 million, and professional services and usage and maintenance agreements of $12.0 million.

Other operating expense (income), net. Other operating expense (income), net consists primarily of miscellaneous revenues including royalties and net gains on asset sales of $14.4 million and net income from equity investments of $5.3 million, partially offset by miscellaneous expenses primarily related to our land company of $7.3 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)
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	$ 1,627,828

Nonoperating expenses in the current period related to our proposed debt restructuring activities and Chapter 11 reorganization. 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 further discussion in Note 14 to the Consolidated Financial Statements, "Taxes,".

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

Revenues. Our revenues consist of coal sales and revenues from our ADDCAR subsidiary prior to its disposition in the first quarter of 2014.

Coal sales. The following table summarizes information about our coal sales during the year ended December 31, 2015 and compares it with the information for the year ended December 31, 2014:

	Predecessor Year Ended December 31, 2015	Predecessor Year Ended December 31, 2014	Increase (Decrease)
	(In thousands)		
Coal sales	$ 2,573,260	$ 2,935,181	$ (361,921)
Tons sold	127,632	134,360	(6,728)

Coal sales decreased in the year ended December 31, 2015 from the year ended December 31, 2014 on a consolidated basis, primarily due to lower tons sold and pricing in our Metallurgical segment and lower tons sold in our Powder River Basin and Other Thermal segments. 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 year ended December 31, 2015 and compares it with the information for the year ended December 31, 2014:

	Predecessor Year Ended December 31, 2015	Predecessor Year Ended December 31, 2014	(Increase) Decrease in Net Loss
	(In thousands)		
Cost of sales (exclusive of items shown separately below)	$ 2,172,753	$ 2,533,284	$ 360,531
Depreciation, depletion and amortization	379,345	418,748	39,403
Accretion on asset retirement obligations	33,680	32,909	(771)
Amortization of sales contracts, net	(8,811)	(13,187)	(4,376)
Change in fair value of coal derivatives and coal trading activities, net	(1,583)	(3,686)	(2,103)
Asset impairment and mine closure costs	2,628,303	24,113	(2,604,190)
Losses from disposed operations resulting from Patriot Coal bankruptcy	116,343	—	(116,343)
Selling, general and administrative expenses	98,783	114,223	15,440
Other operating expense (income), net	19,510	(19,754)	(39,264)
Total costs, expenses and other	$ 5,438,323	$ 3,086,650	$ (2,351,673)

Cost of sales. Our cost of sales decreased in the year ended December 31, 2015 from the year ended December 31, 2014, due to lower transportation costs on lower export sales volumes (a decrease of approximately $66 million), lower diesel fuel costs (approximately $88 million), improved productivity at our Leer longwall operation (approximately $28 million), savings associated with one sold and two idled Appalachian complexes (approximately $77 million), lower sales sensitive costs (approximately $30 million), and other savings associated with cost-control efforts across all regions. See discussion in "Operational Performance" below for more information about regional cost results.

Depreciation, depletion and amortization. When compared with the year ended December 31, 2014, depreciation, depletion and amortization costs decreased in the year ended December 31, 2015 due to the effect of lower production and sales volume, continued low capital spending levels, and the effect of the significant asset impairments at the end of the third quarter of 2015.

Asset impairment and mine closure costs. Continued market deterioration, particularly for Appalachian products, was an indicator of impairment of certain assets. Our testing indicated impairment of several active and undeveloped properties. Impairment costs in the year ended December 31, 2015 include a significant portion of our assets at three operating complexes, and a significant portion of our undeveloped coal reserves value. In the third quarter of 2014, we idled a metallurgical coal mining complex in Appalachia, where we had previously idled two contract mining operations. See Note 5, "Impairment Charges and Mine Closure Costs," to the Consolidated Financial Statements for further discussion.

Losses from disposed operations resulting from the Patriot Coal bankruptcy. In the year ended December 31, 2015 we recorded liabilities related to reclamation and employee obligations that we inherited as a result of the Patriot Coal bankruptcy. See further information regarding the losses related to the Patriot Coal bankruptcy in Note 6, "Losses from disposed operations resulting from Patriot Coal bankruptcy" to the Consolidated Financial Statements.

Selling, general and administrative expenses. Total selling, general and administrative expenses for the year ended December 31, 2015 decreased when compared with the year ended December 31, 2014, primarily due to decreased compensation costs of $13.8 million.

Other operating expense (income), net. When compared with the year ended December 31, 2014, other operating expense (income), net increased during the year ended December 31, 2015, as a result of increased costs of $16.4 million related to shortfalls under throughput arrangements, and lower net gains from sales of assets of $37.1 million. These were partially offset by a $24 million gain on a contract settlement in 2015.

Non-operating expense. The following table summarizes non-operating expense for the year ended December 31, 2015 and compares it with the information for the year ended December 31, 2014:

	Predecessor Year Ended December 31,		(Increase) Decrease in Net Loss
	2015	**2014**	**$**
		(In thousands)	
Net loss resulting from early retirement of debt and debt restructuring	$ (27,910)	$ —	$ (27,910)

Amounts reported as non-operating consist of expenses resulting from financing activities, other than interest costs. In 2015, we incurred $24.2 million of legal and financial advisory fees associated with our debt restructuring efforts. Additionally, in the fourth quarter of 2015 we terminated our revolving credit agreement resulting in the write-off of $3.7 million of deferred financing costs.

Provision for (benefit from) income taxes. The following table summarizes our benefit from income taxes for the year ended December 31, 2015 and compares it with the information for the year ended December 31, 2014:

	Predecessor Year Ended December 31,		Decrease
	2015	**2014**	**in Net Loss**
		(In thousands)	
Provision for (benefit from) income taxes	$ (373,380)	$ 25,634	$ 399,014

The income tax benefit in the year ended December 31, 2015 compared to the income tax provision in the year ended December 31, 2014 was largely due to the approximately $2.6 billion increase in asset impairment losses recorded in 2015 partially offset by the increase of a valuation allowance relating to both federal and state net operating loss carryforwards. See further discussion in Note 14, "Taxes," to the Consolidated Financial Statements for further discussion.

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 acquired 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. In conjunction with our emergence from bankruptcy, we have added accretion on asset retirement obligations as an adjustment to arrive at Adjusted EBITDAR. 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 continuing coal operations for the Predecessor periods January 1 through October 1, 2016 and the years ended December 31, 2015 and 2014.

	Predecessor		
	January 1 through October 1, 2016	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Powder River Basin			
Tons sold (in thousands)	54,911	108,481	111,156
Coal sales per ton sold	$ 13.01	$ 13.15	$ 12.86
Cash cost per ton sold	$ 10.95	$ 10.54	$ 10.87
Cash margin per ton sold	$ 2.06	$ 2.61	$ 1.99
Adjusted EBITDAR (in thousands)	$ 113,185	$ 281,039	$ 218,731
Metallurgical			
Tons sold (in thousands)	6,692	8,352	8,421
Coal sales per ton sold	$ 53.15	$ 66.62	$ 77.70
Cash cost per ton sold	$ 51.40	$ 58.36	$ 64.43
Cash margin per ton sold	$ 1.75	$ 8.26	$ 13.27
Adjusted EBITDAR (in thousands)	$ 11,851	$ 70,450	$ 112,719
Other Thermal			
Tons sold (in thousands)	5,181	9,764	12,201
Coal sales per ton sold	$ 36.16	$ 37.32	$ 37.98
Cash cost per ton sold	$ 30.28	$ 28.01	$ 29.20
Cash margin per ton sold	$ 5.88	$ 9.31	$ 8.78
Adjusted EBITDAR (in thousands)	$ 31,448	$ 42,734	$ 78,238

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 Predecessor 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.

Adjusted EBITDAR increased 29% in 2015 when compared to 2014 due to increased coal sales per ton sold and decreased cash cost per ton sold, partially offset by lower shipment volume. Pricing improved as a significant portion of 2015 shipments were priced following the harsh 2013-2014 winter season when the market was stronger. Cost benefited from lower diesel fuel pricing and cost control efforts. Natural gas pricing fell to historically low levels due to mild winter weather in late

2015, and the competing fuel began to dispatch for electrical generation ahead of Power River Basin coal in some areas. This decrease in coal burn led to increasing generator stockpiles, further depressing demand.

Metallurgical — Adjusted EBITDAR for the Predecessor 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 Predecessor period from January 1 through October 1, 2016. Longwall operations accounted for approximately 65% of our shipment volume in the period.

Adjusted EBITDAR decreased 38% in 2015 when compared to 2014 due to the decrease in coal sales per ton sold partially offset by the decrease in cash cost per ton sold. The decrease in coal sales per ton sold is related to lower metallurgical coal pricing, and the cost reduction is primarily from increased productivity and shifting volume to lower cost operations, particularly the Leer operation. Longwall operations accounted for 59% of our shipment volume in 2015 versus 53% in 2014.

Other Thermal— Adjusted EBITDAR for the Predecessor 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 discussion 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.

Adjusted EBITDAR decreased 45% in 2015 when compared to 2014 due to declining tons sold at our West Elk and Coal Mac operations related to low natural gas pricing and increased liquidated damages costs on logistics contracts.

Reconciliation of NON-GAAP measures

Segment coal sales per ton sold

Segment coal sales per ton sold are calculated as the segment's coal sales revenues divided by segment tons sold. The segments' sales per ton sold 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 statement of operations, but relate to price protection on the sale of coal. Segment sales per ton sold is not a measure of financial performance in accordance with generally accepted accounting principles. We believe segment 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.

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(In thousands)				
Reported segment coal sales revenues	$ 516,448	$ 1,257,219	$ 2,347,132	$ 2,547,075
Coal risk management derivative settlements classified in “other income”	(112)	448	(3,231)	(5,958)
Coal sales revenues from idled or otherwise disposed operations not included in segments	2,181	19,368	48,126	146,823
Transportation costs	57,171	121,674	181,233	247,241
Coal sales	575,688	1,398,709	2,573,260	2,935,181
Other revenues	—	—	—	1,938
Revenues in the consolidated statements of operations	$ 575,688	$ 1,398,709	$ 2,573,260	$ 2,937,119

Segment cost per ton sold

Segment costs per ton sold are calculated as the segment's cost of coal sales divided by segment tons sold. The segments' cost of tons sold 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 statement of operations, but relate directly to the costs incurred to produce coal. Segment cost of tons sold is not a measure of financial performance in accordance with generally accepted accounting principles. We believe segment cost of tons 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 cost of tons sold should not be considered in isolation, nor as an alternative to cost of sales under generally accepted accounting principles.

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(In thousands)				
Reported segment cost of coal sales	$ 399,568	$ 1,102,386	$ 1,903,762	$ 2,106,991
Diesel fuel risk management derivative settlements classified in "other income"	363	(3,696)	(8,162)	(6,789)
Transportation costs	57,171	121,674	181,233	247,241
Cost of sales from idled or otherwise disposed operations not included in segments	5,853	42,513	79,290	190,220
Fresh start coal inventory fair value adjustment	7,345	—	—	—
Other (operating overhead, certain actuarial, etc.)	344	1,587	16,630	(4,379)
Cost of sales in the consolidated statements of operations	$ 470,644	$ 1,264,464	$ 2,172,753	$ 2,533,284

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. We have added accretion on asset retirement obligations as an adjustment to arrive at Adjusted EBITDAR as we believe most industry participants include this adjustment in similar measures. 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.

(In thousands)	Successor: October 2 through December 31, 2016	Predecessor: January 1 through October 1, 2016	Predecessor: Year Ended December 31, 2015	Predecessor: Year Ended December 31, 2014
Reported segment Adjusted EBITDAR from coal operations	$ 117,743	$ 156,484	$ 394,223	$ 409,688
EBITDAR from idled or otherwise disposed operations	(2,795)	(14,514)	(23,605)	(12,834)
Selling, general and administrative expenses	(22,836)	(59,343)	(98,783)	(114,223)
Other	2,385	4,676	11,962	30,421
Adjusted EBITDAR	94,497	87,303	283,797	313,052
Income tax benefit (provision)	(1,156)	4,626	373,380	(25,634)
Interest expense, net	(10,754)	(133,235)	(393,549)	(383,188)
Depreciation, depletion and amortization	(32,604)	(191,581)	(379,345)	(418,748)
Accretion on asset retirement obligations	(7,634)	(24,321)	(33,680)	(32,909)
Amortization of sales contracts, net	(796)	728	8,811	13,187
Asset impairment and mine closure costs	—	(129,267)	(2,628,303)	(24,113)
Losses from disposed operations resulting from Patriot Coal bankruptcy	—	—	(116,343)	—
Net loss resulting from early retirement of debt and debt restructuring	—	(2,213)	(27,910)	—
Reorganization items, net	(759)	1,630,041	—	—
Fresh start coal inventory fair value adjustment	(7,345)	—	—	—
Net income (loss)	$ 33,449	$ 1,242,081	$ (2,913,142)	$ (558,353)

Other includes primarily income from our equity investments, certain actuarial adjustments, and certain changes in the fair value of coal derivatives and coal trading activities.

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

For the Predecessor period from January 1 through October 1, 2016 Other consists primarily of net income from equity investments of $5.3 million.

Other decreased $18.5 million in the Predecessor year ended December 31, 2015 when compared to the Predecessor year ended December 31, 2014 due to the unfavorable year over year net change in pension settlement and curtailment costs of $11.9 million, further unfavorable year over year net change of $4.9 million in other various actuarial liabilities, and reduced net income from equity investments of $2.5 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 growing liquidity and prudently managing costs, including capital expenditures.

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

On the Effective Date, pursuant to the Plan and as a condition to its effectiveness, we entered into a new senior secured term loan credit agreement in an aggregate principal amount of $326.5 million (the “New First Lien Debt Facility”) with

Wilmington Trust, National Association, as administrative agent and collateral agent (in such capacities, the "Agent") for the lenders party thereto from time to time (collectively, the "Lenders"). The term loan matures on October 5, 2021. Borrowings under the term loan bear interest at a per annum rate equal to, at our option, either (i) a London interbank offered rate plus an applicable margin of 9%, per annum subject to a 1% LIBOR floor (the "LIBOR Rate"), or (ii) a base rate plus an applicable margin of 8% per annum. Interest payments are payable in cash, unless our Liquidity (as defined therein) after giving effect to the applicable interest payment would not exceed $300 million, in which case interest shall be payable in kind. To the extent any interest is paid in kind on any interest payment date, the amount of the term loans in respect of which such paid-in-kind interest is payable will be deemed to have accrued additional interest over the preceding interest period at a rate of 1.00% per annum, which additional interest will be capitalized and added to the principal amount of outstanding term loans. Quarterly principal amortization payments in an amount equal to $816,250 are required under the term loan. We have the right to prepay the term loan at any time and from time to time in whole or in part without premium or penalty, upon written notice, except that any prepayment of term loans that bear interest at the LIBOR Rate other than at the end of the applicable interest periods therefor shall be made with reimbursement for any funding losses and redeployment costs of the Lenders resulting therefrom.

On the Effective Date, we extended and amended our existing $200 million trade accounts receivable securitization facility provided to Arch Receivable Company, LLC ("Arch Receivable"), a non-Debtor special-purpose entity that is a wholly owned subsidiary of Arch Coal (the "Extended Securitization Facility"), which continues to support the issuance of letters of credit and reinstates Arch Receivable's ability to request cash advances, as existed prior to the filing of the voluntary petitions for relief under the Bankruptcy Code. The Extended Securitization Facility will terminate at the earliest of (i) three years from the Effective Date, (ii) if the Liquidity (as defined in the Extended Securitization Facility and consistent with the definition in the New First Lien Debt Facility) is less than $175 million for a period of 60 consecutive days, the date that is the 364th day after the first day of such 60 consecutive day period and (iii) the occurrence of certain predefined events substantially consistent with the existing transaction documents. As of December 31, 2016, letters of credit totaling $154.4 million were outstanding under the Extended Securitization Facility and the borrowing base was $83.4 million. As a result, cash collateral of $71.0 million has been placed in the Extended Securitization Facility at December 31, 2016 and there is no availability for borrowings.

The following is a summary of cash provided by or used in each of the indicated types of activities:

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In thousands)			
Cash provided by (used in):				
Operating activities	$ 84,192	$ (228,218)	$ (44,367)	$ (33,582)
Investing activities	17,984	15,134	(180,341)	(111,434)
Financing activities	2,709	(37,210)	(58,742)	(31,852)

Cash Flow - Successor

Cash provided by operating activities in the Successor period October 2 through December 31, 2016 resulted from improved market conditions for most of our products and solid operating cost performance across all of our segments discussed in the Operational Performance section above. In addition, low cash interest expense and favorable working capital adjustments contributed to the cash provided by operating activities.

Cash provided by investing activities in the Successor period October 2 through December 31, 2016 resulted from the sale of short term investments and withdrawals of restricted cash as collateral requirements under the securitization facility discussed above diminished over the period. These benefits were partially offset by capital expenditures that have been effectively managed to minimal levels.

Cash provided by financing activities in the Successor period October 2 through December 31, 2016 resulted from insurance premium financing proceeds partially offset by the first principal amortization payment on the term loan discussed above.

Cash Flow - Predecessor

Cash used in operating activities in the Predecessor period January 1 through October 1, 2016 resulted from difficult market conditions for all of our products as discussed in the Operational Performance section above. In addition significant cash interest expense and cash restructuring costs impacted cash used in operating activities.

Cash used in operating activities in the Predecessor years ended December 31, 2015 and December 31, 2014 resulted from deteriorating market conditions and high cash interest expenses.

Cash provided by investing activities in the Predecessor period January 1 through October 1, 2016 resulted from the net sale of short term investments and withdrawals of restricted cash as collateral requirements under the Predecessor securitization facility diminished over the period. These benefits were partially offset by capital expenditures that were effectively managed to minimal levels, but did include the final of five annual $60 million lease by application bonus bid payments for reserves acquired in the Powder River Basin.

Cash used in investing activities in the Predecessor year ended December 31, 2015 increased from the Predecessor year ended December 31, 2014 due to increased deposits of restricted cash as collateral requirements under the Predecessor securitization facility increased over the 2015 period, and the absence of significant proceeds from disposals and divestitures in the year ended December 31, 2015 versus approximately $62 million in proceeds in the year ended December 31, 2014. These benefits were partially offset by decreased capital spending and net proceeds from the sale of short term investments in 2015 versus 2014.

Cash used in financing activities in the Predecessor period January 1 through October 1, 2016 resulted from financing costs associated with the previous DIP facility and securitization facility discussed above, insurance premium financing payments, and expenses related to pre-filing debt restructuring costs.

Cash used in financing activities in the Predecessor year ended December 31, 2015 increased from the Predecessor year ended December 31, 2014 due to expenses related to pre-filing debt restructuring costs in 2015.

Contractual Obligations

	Payments Due by Period				
	2017	2018-2019	2020-2021	after 2021	Total
	(Dollars in thousands)				
Long-term debt, including related interest	$ 44,148	$ 86,465	$ 389,368	$ 290	$ 520,271
Operating leases	14,653	19,806	4,245	10,317	49,021
Coal lease rights	3,994	12,126	14,956	46,499	77,575
Coal purchase obligations	8,406	—	—	—	8,406
Unconditional purchase obligations	39,571	—	—	—	39,571
Total contractual obligations	$ 110,772	$ 118,397	$ 408,569	$ 57,106	$ 694,844

The related interest on long-term debt was calculated using rates in effect at December 31, 2016 for the remaining term of outstanding borrowings.

Coal lease rights represent non-cancelable royalty lease agreements, as well as lease bonus payments due.

Unconditional purchase obligations include open purchase orders and other purchase commitments, which have not been recognized as a liability. The commitments in the table above relate to contractual commitments for the purchase of materials and supplies, payments for services and capital expenditures.

The table above excludes our asset retirement obligations. Our consolidated balance sheet reflects a liability of $356.7 million for asset retirement obligations that arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Asset retirement obligations are recorded at fair value when incurred and accretion expense is recognized through the expected date of settlement. Determining the fair value of asset retirement obligations involves a number of estimates, as discussed in the section entitled "Critical Accounting Policies" below, including the timing of payments to satisfy the obligations. The timing of payments to satisfy asset retirement obligations is based on numerous factors, including mine closure dates. Please see the notes to our Consolidated Financial Statements for more information about our asset retirement obligations.

The table above also excludes certain other obligations reflected in our consolidated balance sheet, including estimated funding for pension and postretirement benefit plans and worker's compensation obligations. The timing of contributions to our pension plans varies based on a number of factors, including changes in the fair value of plan assets and actuarial assumptions. Please see the section entitled "Critical Accounting Policies" below for more information about these assumptions. We expect to make contributions of $0.4 million to our pension plans in 2017, which is impacted by the Moving Ahead for Progress in the 21st Century Act (MAP-21) enacted July 6, 2012. MAP-21 does not reduce our obligations under the plan, but redistributes the timing of required payments by providing near term funding relief for sponsors under the Pension Protection Act.

Please see the Notes to our Consolidated Financial Statements for more information about the amounts we have recorded for workers' compensation and pension and postretirement benefit obligations.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees, indemnifications, financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

We use a combination of surety bonds, letters of credit and cash to secure our financial obligations for reclamation, workers' compensation, coal lease obligations and other obligations as follows as of December 31, 2016:

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Other	Total
			(Dollars in thousands)		
Surety bonds	528,301	32,584	19,534	2,824	583,243
Letters of credit	21,321	—	115,568	17,547	154,436
Cash on deposit with others	33,409	—	11,132	—	44,541

Critical Accounting Policies

We prepare our financial statements in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management bases our estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Additionally, these estimates and judgments are discussed with our audit committee on a periodic basis. Actual results may differ from the estimates used under different assumptions or conditions. We have provided a description of all significant accounting policies in the notes to our Consolidated Financial Statements. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity:

Fresh Start Accounting

On the plan Effective Date, the Company applied fresh start accounting which requires the Company 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.

Fresh start accounting provides, among other things, for a determination of the value to be assigned to the equity of the emerging company as of a date selected for financial reporting purposes. In conjunction with the bankruptcy proceedings, a third party financial advisor provided an enterprise value of the Company of approximately $650 million to $950 million. The final equity value of $687.5 million was based upon the approximate high end of the enterprise value established by the third party valuation. The high end of the enterprise assumed a minimum cash balance at emergence of $250 million.

The enterprise value of the Company was estimated using various valuation methods including: (i) comparable public company analysis, (ii) discounted cash flow analysis (“DCF”) and (iii) sum-of-the-parts analysis.

All estimates, assumptions and financial projections, including the fair value adjustments, the financial projections, and the enterprise value and reorganization value projections, are inherently subject to significant uncertainties. Accordingly, there can be no assurance that the estimates, assumptions and financial projections will be realized, and actual results could vary materially.

For the impact of the adoption of fresh start accounting, see Note 3, “Emergence from Bankruptcy and Fresh Start Accounting,” of the Notes to the Consolidated Financial Statements.

Derivative Financial Instruments

We utilize derivative instruments to manage exposures to commodity prices. Additionally, we may hold certain coal derivative instruments for trading purposes. Derivative financial instruments are recognized in the balance sheet at fair value. Certain coal contracts may meet the definition of a derivative instrument, but because they provide for the physical purchase or sale of coal in quantities expected to be used or sold by us over a reasonable period in the normal course of business, they are not recognized on the balance sheet.

Certain derivative instruments are designated as the hedge instrument in a hedging relationship. In a cash flow hedge, we hedge the risk of changes in future cash flows related to a forecasted purchase or sale. Changes in the fair value of the derivative instrument used as a hedge instrument in a cash flow hedge are recorded in other comprehensive income. Amounts in other comprehensive income are reclassified to earnings when the hedged transaction affects earnings and are classified in a manner consistent with the transaction being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking various hedge transactions. We evaluate the effectiveness of our hedging relationships both at the hedge inception and on an ongoing basis.

Impairment of Long-lived Assets

We review our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These events and circumstances include, but are not limited to, a current expectation that a long-lived asset will be disposed of significantly before the end of its previously estimated useful life, a significant adverse change in the extent or manner in which we use a long-lived asset or a change in its physical condition.

When such events or changes in circumstances occur, a recoverability test is performed comparing projected undiscounted cash flows from the use and eventual disposition of an asset or asset group to its carrying amount. If the projected undiscounted cash flows are less than the carrying amount, an impairment is recorded for the excess of the carrying amount over the estimate fair value, which is generally determined using discounted future cash flows. If we recognize an impairment loss, the adjusted carrying amount of the asset becomes the new cost basis. For a depreciable long-lived asset, the new cost basis will be depreciated (amortized) over the remaining estimated useful life of the asset.

We make various assumptions, including assumptions regarding future cash flows in our assessments of long-lived assets for impairment. The assumptions about future cash flows and growth rates are based on the current and long-term business plans related to the long-lived assets. Discount rate assumptions are based on an assessment of the risk inherent in the future cash flows of the long-lived assets. These assumptions require significant judgments on our part, and the conclusions that we reach could vary significantly based upon these judgments.

For additional information on impairment charges related to this filing, see Note 5, “Impairment Charges and Mine Closure Costs” to the Consolidated Financial Statements.

Asset Retirement Obligations

Our asset retirement obligations arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Significant reclamation activities include reclaiming refuse and slurry ponds, reclaiming the pit and support acreage at surface mines, and sealing portals at deep mines. Our asset retirement obligations are initially recorded at fair value, or the amount at which the obligations could be settled in a current transaction between willing parties. This involves determining the present value of estimated future cash flows on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity. We estimate disturbed acreage based on approved mining plans and related engineering data. Since we plan to use internal resources to perform the majority of our reclamation activities, our estimate of reclamation costs involves estimating third-party profit margins, which we base on our historical experience with contractors that perform certain types of reclamation activities. We base productivity assumptions on historical experience with the equipment that we expect to utilize in the reclamation activities. In order to determine fair value, we discount our estimates of cash flows to their present value. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

Accretion expense is recognized on the obligation through the expected settlement date. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing and extent of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled. We expect our actual cost to reclaim our properties will be less than the expected cash flows used to determine the asset retirement obligation. At December 31, 2016, our balance sheet reflected asset retirement obligation liabilities of $356.7 million, including amounts classified as a current liability. As of December 31, 2016, we estimate the aggregate undiscounted cost of final mine closures to be approximately $926 million.

See the rollforward of the asset retirement obligation liability in Note 15 to the Consolidated Financial Statements, “Asset Retirement Obligations”.

Employee Benefit Plans

We have non-contributory defined benefit pension plans covering certain of our salaried and hourly employees. Benefits are generally based on the employee’s years of service and compensation. The actuarially-determined funded status of the defined benefit plans is reflected in the balance sheet.

The calculation of our net periodic benefit costs (pension expense) and benefit obligation (pension liability) associated with our defined benefit pension plans requires the use of a number of assumptions. These assumptions are summarized in Note 20, “Employee Benefit Plans”, to the Consolidated Financial Statements. Changes in these assumptions can result in different pension expense and liability amounts, and actual experience can differ from the assumptions.

- The expected long-term rate of return on plan assets is an assumption reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan’s investment targets are 55% equity and 45% fixed income securities. Investments are rebalanced on a periodic basis to approximate these targeted guidelines. The long-term rate of return assumptions are less than the plan’s actual life-to-date returns. Any difference between the actual experience and the assumed experience is recorded in other comprehensive income and amortized into earnings in the future. The impact of lowering the expected long-term rate of return on plan assets 0.5% for 2016 would have been an increase in expense of approximately $1.4 million.
- The discount rate represents our estimate of the interest rate at which pension benefits could be effectively settled. Assumed discount rates are used in the measurement of the projected, accumulated and vested benefit obligations and the service and interest cost components of the net periodic pension cost. The determination of the discount rate was updated from our actuary’s proprietary Yield Curve model, under which the expected benefit payments of the plan are matched against a series of spot rates from a market basket of high quality fixed income securities. The impact of lowering the discount rate 0.5% for 2016 would have been an increase in expense of approximately $1.2 million.

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings using the corridor method, whereby the unrecognized (gains)/losses in excess of 10% of the greater of the beginning of the year projected benefit obligation or market-related value of assets are amortized over the average remaining life expectancy of the plan participants.

We also currently provide certain postretirement medical and life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement benefit plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance.

Actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. The discount rate assumption reflects the rates available on high-quality fixed-income debt instruments at year-end and is calculated in the same manner as discussed above for the pension plan. A change of 0.5% in these assumptions would not have had a significant impact on the benefit costs in 2016 .

Income Taxes

We provide for deferred income taxes for temporary differences arising from differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. We initially recognize the effects of a tax position when it is more than 50 percent likely, based on the technical merits, that the position will be sustained upon examination, including resolution of the related appeals or litigation processes, if any. Our determination of whether or not a tax position has met the recognition threshold considers the facts, circumstances, and information available at the reporting date.

We reassess our ability to realize our deferred tax assets annually in the fourth quarter, during our annual budget process, or when circumstances indicate that the ability to realize deferred tax assets has changed. The assessment takes into account expectations of future taxable income or loss, available tax planning strategies and the reversal of temporary differences. The development of these expectations involves the use of estimates such as production levels, operating profitability, timing of development activities and the cost and timing of reclamation work. A valuation allowance may be recorded to reflect the amount of future tax benefits that management believes are not likely to be realized. If actual outcomes differ from our expectations, we may record additional valuation allowance through income tax expense in the period such determination is made.

As our recent cumulative losses constitute significant negative evidence with regards to future taxable income, we have relied solely on the expected reversal of taxable temporary differences to support the future realization of our deferred tax assets. We perform a detailed scheduling process of our net taxable temporary differences.

At December 31, 2014, all deductible temporary differences were expected to be realized as there were sufficient deferred tax liabilities within the same jurisdiction and of the same character that are available to offset them. Valuation allowances were established for federal and state net operating losses and tax credits that were not offset by the reversal of other net taxable temporary differences before the expiration of the attribute.

At December 31, 2015, additional losses were realized relating primarily to financial conditions and asset impairment charges. As a result, the expected reversal of taxable temporary differences were not sufficient to support the future realization of the deferred tax assets and an additional $865.1 million valuation allowance was recorded. Net deferred tax assets of $1,135 million were completely offset by a valuation allowance.

At December 31, 2016, additional tax losses were realized primarily as a result of the non-recognition of CODI under section 108 of the IRC by the Predecessor entity. As a result, the expected reversal of taxable temporary differences were not sufficient to support the future realization of the deferred tax assets and an additional $1,185 million valuation allowance was recorded to the provision. Offsetting this increase was a net reduction in the valuation allowance of $1,289 million which did not impact the provision. This reduction was primarily the result of a decrease in NOLs and AMT credits due to the IRC section 108 offset rules. Net deferred tax assets of $1,022 million are completely offset by a valuation allowance.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We manage our commodity price risk for our non-trading, thermal coal sales through the use of long-term coal supply agreements, and to a limited extent, through the use of derivative instruments. Sales commitments in the metallurgical coal market are typically not long-term in nature, and we are therefore subject to fluctuations in market pricing.

Our commitments for 2017 are as follows:

	2017	
	Tons	**$ per ton**
Metallurgical	**(in millions)**	
Committed, Priced Coking	3.3	$ 89.70
Committed, Unpriced Coking	1.7	
Committed, Priced PCI	0.7	$ 64.82
Committed, Unpriced PCI	—	
Committed, Priced Thermal	1.0	$ 34.52
Committed, Unpriced Thermal	—	
Powder River Basin		
Committed, Priced	66.1	$ 12.51
Committed, Unpriced	3.3	
Other Thermal		
Committed, Priced	6.6	$ 35.76
Committed, Unpriced	—	

We are also exposed to commodity price risk in our coal trading activities, which represents the potential future loss that could be caused by an adverse change in the market value of coal. Our coal trading portfolio included forward, swap and put and call option contracts at December 31, 2016. The estimated future realization of the value of the trading portfolio is $0.2 million of gains in 2017.

We monitor and manage market price risk for our trading activities with a variety of tools, including Value at Risk (VaR), position limits, management alerts for mark to market monitoring and loss limits, scenario analysis, sensitivity analysis and review of daily changes in market dynamics. Management believes that presenting high, low, end of year and average VaR is the best available method to give investors insight into the level of commodity risk of our trading positions. Illiquid positions, such as long-dated trades that are not quoted by brokers or exchanges, are not included in VaR.

VaR is a statistical one-tail confidence interval and down side risk estimate that relies on recent history to estimate how the value of the portfolio of positions will change if markets behave in the same way as they have in the recent past. While presenting VaR will provide a similar framework for discussing risk across companies, VaR estimates from two independent sources are rarely calculated in the same way. Without a thorough understanding of how each VaR model was calculated, it would be difficult to compare two different VaR calculations from different sources. The level of confidence is 95%. The time across which these possible value changes are being estimated is through the end of the next business day. A closed-form delta-neutral method used throughout the finance and energy sectors is employed to calculate this VaR. VaR is back tested to verify usefulness.

On average, portfolio value should not fall more than VaR on 95 out of 100 business days. Conversely, portfolio value declines of more than VaR should be expected, on average, 5 out of 100 business days. When more value than VaR is lost due to market price changes, VaR is not representative of how much value beyond VaR will be lost.

During the year ended December 31, 2016, VaR for our coal trading positions that are recorded at fair value through earnings ranged from under $0.1 million to $0.3 million. The linear mean of each daily VaR was $0.1 million. The final VaR at December 31, 2016 was $0.1 million.

We are exposed to fluctuations in the fair value of coal derivatives that we enter into to manage the price risk related to future coal sales, but for which we do not elect hedge accounting. Any gains or losses on these derivative instruments would be offset in the pricing of the physical coal sale. During the year ended December 31, 2016 VaR for our risk management positions that are recorded at fair value through earnings ranged from $0.1 million to $0.2 million. The linear mean of each daily VaR was $0.1 million. The final VaR at December 31, 2016 was $0.1 million.

We are also exposed to the risk of fluctuations in cash flows related to our purchase of diesel fuel. We expect to use approximately 45 to 50 million gallons of diesel fuel for use in our operations during 2017. We may enter into forward physical purchase contracts, as well as purchased heating oil options, to reduce volatility in the price of diesel fuel for our operations. At December 31, 2016, we had purchased heating oil call options for approximately 31 million gallons for the purpose of protecting against substantial increases in price relating to 2017 diesel purchases. These positions reduce our risk of cash flow fluctuations related to these surcharges but the positions are not accounted for as hedges. A $0.25 per gallon decrease in the price of heating oil would not result in an increase in our expense related to the heating oil derivatives. We also at times have purchased heating oil call options to manage the price risk associated with fuel surcharges on barge and rail shipments, which cover increases in diesel fuel prices. At December 31, 2016, we had no positions outstanding for this purpose.

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2016, of our $362.9 million principal amount of debt outstanding, approximately $325.7 million of outstanding borrowings have interest rates that fluctuate based on changes in the market rates. An increase in the interest rates related to these borrowings of 25 basis points would not result in an annualized increase in interest expense based on interest rates in effect at December 31, 2016, because our term loan has a minimum interest rate that exceeds the current market rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The Consolidated Financial Statements and consolidated financial statement schedule of Arch Coal, Inc. and subsidiaries are included in this Annual Report on Form 10-K beginning on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

We performed an evaluation under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2016. Based on that evaluation, our management, including our chief executive officer and chief financial officer, concluded that the disclosure controls and procedures were effective as of such date. There were no changes in our internal control over financial reporting during the fiscal quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We incorporate by reference management's report on internal control over financial reporting included within the Financial Statement section of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Except for the disclosures contained in Part I of this report under the caption “Executive Officers of the Registrant”, the information required under this item is incorporated herein by reference to “Director Qualifications, Diversity and Biographies,” “Section 16(a) Beneficial Ownership Reporting Compliance,” “Corporate Governance Guidelines and Code of Business Conduct,” “Nomination Process for Election of Directors” and “Board Meetings and Committees” in our Proxy Statement for the 2017 Annual Meeting of Stockholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION.

The information required under this item is incorporated herein by reference to “Executive Compensation,” “Director Compensation,” “Compensation Committee Interlocks and Inside Participation” and “Personnel and Compensation Committee Report” in our Proxy Statement for the 2017 Annual Meeting of Stockholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required under this item is incorporated herein by reference to “Equity Compensation Plan Information,” “Security Ownership of Directors and Executive Officers” and “Security Ownership of Certain Beneficial Owners” in our Proxy Statement for the 2017 Annual Meeting of Stockholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required under this item is incorporated herein by reference to “Director Independence” in our Proxy Statement for the 2017 Annual Meeting of Stockholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required under this item is incorporated herein by reference to “Fees Paid to Auditors” in our Proxy Statement for the 2017 Annual Meeting of Stockholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

Financial Statements

Reference is made to the index set forth on page F-1 of this report.

Financial Statement Schedules

The following financial statement schedule of Arch Coal, Inc. is at the page indicated:

Schedule	Page
Valuation and Qualifying Accounts	F- 61

All other financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

Exhibits

Reference is made to the Exhibit Index beginning on page 79 of this report.

ITEM 16. FORM 10-K SUMMARY.

None.

Signatures

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

Arch Coal, Inc.

/s/ John W. Eaves

John W. Eaves
Chief Executive Officer, Director
February 24, 2017

Signatures	Capacity	Date
/s/ John W. Eaves John W. Eaves	Chief Executive Officer, Director (Principal Executive Officer)	February 24, 2017
/s/ John T. Drexler John T. Drexler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2017
/s/ John W. Lorson John W. Lorson	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2017
* James N. Chapman	Chairman	February 24, 2017
* Patrick J. Bartels, Jr.	Director	February 24, 2017
* Sherman K. Edmiston III	Director	February 24, 2017
* Patrick A. Kriegshauser	Director	February 24, 2017
* Richard A. Navarre	Director	February 24, 2017
* Scott D. Vogel	Director	February 24, 2017

*By /s/ Robert G. Jones

Robert G. Jones,
Attorney-in-Fact

Exhibits to be included in 10-K

	Description
Exhibit 2.1	Debtors' Fourth Amended Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.1 of Arch Coal's Current Report on Form 8-K on September 15, 2016).
Exhibit 2.2	Order Confirming Debtors' Fourth Amended Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code on September 13, 2016 (incorporated by reference to Exhibit 2.2 of Arch Coal's Current Report on Form 8-K filed on September 15, 2016).
Exhibit 3.1	Amended and Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated by reference to Exhibit 3.1 of Arch Coal's registration statement on Form 8-K filed on October 4, 2016).
Exhibit 3.2	Bylaws of Arch Coal, Inc. (incorporated by reference to Exhibit 3.2 of Arch Coal's registration statement on Form 8-K filed on October 4, 2016).
Exhibit 4.1	Indenture, dated as of August 9, 2010, by and between Arch Coal, Inc. and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Arch Coal's Current Report on Form 8-K filed on August 9, 2010)
Exhibit 4.2	First Supplemental Indenture, dated as of August 9, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Arch Coal's Current Report on Form 8-K filed on August 9, 2010)
Exhibit 4.3	Second Supplemental Indenture, dated as of December 16, 2010, by and among Arch Coal West, LLC, Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.7 to Arch Coal's Annual Report on Form 10-K for the period ended December 31, 2010).
Exhibit 4.4	Third Supplemental Indenture, dated as of June 24, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.13 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).
Exhibit 4.5	Fourth Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.14 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).
Exhibit 4.6	Fifth Supplemental Indenture, dated as of July 2, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
Exhibit 4.7	Sixth Supplemental Indenture, dated as of July 31, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.5 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
Exhibit 4.8	Seventh Supplemental Indenture, dated as of July 26, 2013, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2013).
Exhibit 4.9	Eighth Supplemental Indenture, dated December 2, 2013, by and among Arch Coal, Inc. the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.21 to Arch Coal's Annual Report on Form 10-K for the period ended December 31, 2013).
Exhibit 4.10	Indenture, dated as of June 14, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Arch Coal's Current Report on Form 8-K filed on June 14, 2011).
Exhibit 4.11	First Supplemental Indenture, dated as of July 5, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.16 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).
Exhibit 4.12	Second Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.17 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).
Exhibit 4.13	Third Supplemental Indenture, dated as of July 2, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
Exhibit 4.14	Fourth Supplemental Indenture, dated as of July 31, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.6 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2012).

Exhibit 4.15 Fifth Supplemental Indenture, dated as of July 26, 2013, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2013).

Exhibit 4.16 Sixth Supplemental Indenture, dated as of December 2, 2013, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association (incorporated herein by reference to Exhibit 4.28 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2013).

Exhibit 4.17 Indenture, dated as of November 21, 2012, among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Arch Coal's Current Report on Form 8-K filed on November 26, 2012).

Exhibit 4.18 First Supplemental Indenture, dated as of July 26, 2013, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.4 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2013).

Exhibit 4.19 Second Supplemental Indenture, dated as of December 2, 2013, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.31 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2013).

Exhibit 4.20 Indenture, dated as of December 17, 2013, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee and collateral agent (incorporated herein by reference to Exhibit 4.1 to Arch Coal's Current Report on Form 8-K filed on December 17, 2013).

Exhibit 4.21 Form of specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.1of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 4.22 Form of specimen Class B Common Stock Certificate (incorporated by reference to Exhibit 4.1of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 4.23 Form of specimen Series A Warrant Certificate (incorporated by reference to Exhibit 4.1of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.1 Amended and Restated Credit Agreement, dated as of June 14, 2011, by and among the Company, the lenders party thereto, PNC Bank, National Association, as administrative agent and Bank of America, N.A., The Royal Bank of Scotland PLC and Citibank, N.A., as co-documentation agents (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Arch Coal on June 17, 2011).

Exhibit 10.2 Incremental Amendment, dated as of November 21, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the incremental term loan lenders party thereto, Bank of America, N.A., as Term Loan Administrative Agent, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, PNC Capital Markets LLC, Morgan Stanley Senior Funding, Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, BBVA Securities Inc., RBS Securities Inc. and Union Bank, N.A., as Lead Arrangers, as Lead Arrangers (incorporated herein by reference to Exhibit 10.1 to Arch Coal's Current Report on Form 8-K filed on November 26, 2012).

Exhibit 10.3 First Amendment to Amended and Restated Credit Agreement, dated as of May 16, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the lenders party thereto, and PNC Bank, National Association, as Revolver Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Arch Coal's Current Report on Form 8-K filed on May 17, 2012).

Exhibit 10.4 Second Amendment to Amended and Restated Credit Agreement, dated as of November 21, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the lenders party thereto, Bank of America, N.A., as Term Loan Administrative Agent, and PNC Bank, National Association, as Revolver Administrative Agent (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Current Report on Form 8-K filed on November 26, 2012).

Exhibit 10.5 Third Amendment to Amended and Restated Credit Agreement, dated as of November 21, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the revolver lenders party thereto and PNC Bank, National Association, as Revolver Administrative Agent (incorporated herein by reference to Exhibit 10.3 to Arch Coal's Current Report on Form 8-K filed on November 26, 2012).

Exhibit 10.6 Amendment Number Four to Amended and Restated Credit Agreement, dated as of December 17, 2013, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the lenders party thereto, Bank of America, N.A., as term loan administrative agent, and PNC Bank, National Association, as Revolver Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Arch Coal's Current Report on Form 8-K filed on December 17, 2013).

Exhibit 10.7 Credit Agreement, dated as of October 5, 2016, among Arch Coal, Inc., as borrower, the lenders from time to time party thereto and Wilmington Trust, National Association, in its capacities as administrative agent and as collateral agent (incorporated by reference to Exhibit 10.1 of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.8 Amended and Restated Receivables Purchase Agreement, dated as of February 24, 2010, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, as issuer, the financial institutions form time to time party thereto, as LC Participants, and PNC Bank, National Association, as Administrator on behalf of the Purchasers and as LC Bank (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Quarterly Report on Form 10-Q for the period ended March 31, 2010).

Exhibit 10.9 First Amendment to Amended and Restated Receivables Purchase Agreement, dated January 31, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated by reference to Exhibit 10.41 to Arch Coal's Annual Report on Form 10-K for the period ended December 31, 2010).

Exhibit 10.10 Second Amendment to Amended and Restated Receivables Purchase Agreement dated June 15, 2011 (incorporated by reference to Exhibit 10.5 to Arch Coal's Quarterly Report on Form 10-Q for the period ended June 30, 2011).

Exhibit 10.11 Third Amendment to Amended and Restated Receivables Purchase Agreement dated November 21, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated herein by reference to Exhibit 10.38 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).

Exhibit 10.12 Fourth Amendment to Amended and Restated Receivables Purchase Agreement dated December 13, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated herein by reference to Exhibit 10.39 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).

Exhibit 10.13 Fifth Amendment to Amended and Restated Receivables Purchase Agreement dated December 11, 2012, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated herein by reference to Exhibit 10.45 to Arch Coal's Annual Report on Form 10-K for the period ended December 31, 2012).

Exhibit 10.14 Sixth Amendment to Amended and Restated Receivables Purchase Agreement dated October 4, 2013, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., and the other parties thereto (incorporated herein by reference to Exhibit 10.51 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2013).

Exhibit 10.15 Seventh Amendment to Amended and Restated Receiveables Purchase Agreement dated December 10, 2013, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., and the other parties thereto (incorporated herein by reference to Exhibit 10.52 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2013).

Exhibit 10.16 Eighth Amendment to Amended and Restated Receivables Purchase Agreement dated October 28, 2014, among Arch Receivables Company, LLC, Arch Coal Sales Company, Inc., and the other parties thereto (incorporated by reference to Exhibit 10.54 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit 10.17 Ninth Amendment to Amended and Restated Receivables Purchase Agreement, dated December 29, 2014, among Arch Receivables Company, LLC, Arch Coal Sales Company, Inc., and the other parties thereto (incorporated herein by reference to Exhibit 10.55 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit 10.18 Second Amended and Restated Purchase and Sale Agreement among Arch Coal, Inc. and certain subsidiaries of Arch Coal, Inc., as originators (incorporated by reference to Exhibit 10.3 of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.19 Third Amended and Restated Receivables Purchase Agreement among Arch Receivable Company, LLC, as seller, Arch Coal Sales Company, Inc., as initial servicer, PNC Bank, National Association as administrator and issuer of letters of credit thereunder and the other parties party thereto, as securitization purchasers (incorporated by reference to Exhibit 10.2 of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.20 Second Amended and Restated Sale and Contribution Agreement between Arch Coal, Inc., as the transferor, and Arch Receivable Company, LLC (incorporated by reference to Exhibit 10.4 of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.21 Warrant Agreement, dated as of October 5, 2016, between Arch Coal, Inc. and American Stock Transfer & Trust Company, LLC, as Warrant Agent (incorporated by reference to Exhibit 10.5 of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.22 Indemnification Agreement between Arch Coal and the directors and officers of Arch Coal and its subsidiaries (form) (incorporated by reference to Exhibit 10.6 of Arch Coal's Current Report on Form 8-K filed on October 11, 2016).

Exhibit 10.23 Registration Rights Agreement between Arch Coal and Monarch Alternative Capital LP and certain other affiliated funds (incorporated by reference to Exhibit 10.1 of Arch Coal's Current Report on Form 8-K filed on November 21, 2016)

Exhibit 10.24 Coal Lease Agreement dated as of March 31, 1992, among Allegheny Land Company, as lessee, and UAC and Phoenix Coal Corporation, as lessors, and related guarantee (incorporated herein by reference to the Current Report on Form 8-K filed by Ashland Coal, Inc. on April 6, 1992).

Exhibit 10.25 Federal Coal Lease dated as of January 24, 1996 between the U.S. Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).

Exhibit 10.26 Federal Coal Lease Readjustment dated as of November 1, 1967 between the U.S. Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).

Exhibit 10.27 Federal Coal Lease effective as of May 1, 1995 between the U.S. Department of the Interior and Mountain Coal Company (incorporated herein by reference to Exhibit 10.22 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).

Exhibit 10.28 Federal Coal Lease dated as of January 1, 1999 between the Department of the Interior and Ark Land Company (incorporated herein by reference to Exhibit 10.23 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).

Exhibit 10.29 Federal Coal Lease effective as of March 1, 2005 by and between the United States of America and Ark Land LT, Inc. covering the tract of land known as "Little Thunder" in Campbell County, Wyoming (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by the registrant on February 10, 2005).

Exhibit 10.30 Modified Coal Lease (WYW71692) executed January 1, 2003 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as "North Rochelle" in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).

Exhibit 10.31 Coal Lease (WYW127221) executed January 1, 1998 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as "North Roundup" in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).

Exhibit 10.32 Form of Employment Agreement for Executive Officers of Arch Coal, Inc. (incorporated herein by reference to Exhibit 10.4 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2011).

Exhibit 10.33 Arch Coal, Inc. Incentive Compensation Plan For Executive Officers (incorporated herein by reference to Appendix B to the proxy statement on Schedule 14A filed by the registrant on March 22, 2010).

Exhibit 10.34 Arch Coal, Inc. Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.26 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit 10.35 Arch Coal, Inc. Outside Directors' Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.4 of Arch Coal's Current Report on Form 8-K filed on December 11, 2008).

Exhibit 10.36 Arch Coal, Inc. Supplemental Retirement Plan (as amended on December 5, 2008) (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Current Report on Form 8-K filed on December 11, 2008).

Exhibit 10.37 Arch Coal, Inc. 2016 Omnibus Incentive Plan (incorporated herein by reference to Exhibit 99.1 to Arch Coal's Registration Statement on Form S-8 filed on November 1, 2016).

Exhibit 10.38 Form of Restricted Stock Unit Contract (Time-Based Vesting) (incorporated herein by reference to Exhibit 10.1 to Arch Coal's Current Report on Form 8-K filed on November 30, 2016).

Exhibit 10.39 Form of Restricted Stock Unit Contract (Performance-Based Vesting) (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Current Report on Form 8-k filed on November 30, 2016).

Exhibit 10.40 Form of Performance Unit Contract (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Quarterly Report on Form 10-Q for the period ended March 31, 2013).

Exhibit 10.41 Form of 2011 Performance Unit Contract (incorporated herein by reference to Exhibit 10.4 to Arch Coal's Quarterly Report on Form 10-Q for the period ended March 31, 2012).

Exhibit 10.42 Form of Director Indemnity Agreement (incorporated herein by reference to Exhibit 10.40 to Arch Coal's Annual Report on Form 10-K for the period ended December 31, 2010).

Exhibit 10.43 Superpriority Senior Secured Debtor in Possession Credit Agreement, dated as of January 21, 2016, by and among Arch Coal, Inc., subsidiaries of Arch Coal, Inc. from time to time party thereto as guarantors, the lenders from time to time party thereto and the Agent (as defined therein) (incorporated herein by reference to Exhibit 10.53 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2015).

Exhibit 10.44 Amendment No. 2, dated as of March 25, 2016, to the Superpriority Secured Debtor-in-Possession Credit Agreement dated January 21, 2016 (incorporated herein by reference to Exhibit 10.1 to Arch Coal's Quarterly Report on Form 10-Q filed on May 10, 2016).

Exhibit 10.45 Amendment No. 3, dated as of April 26, 2016, to the Superpriority Secured Debtor-in-Possession Credit Agreement dated January 21, 2016 (incorporated herein by reference to Exhibit 10.1 to Arch Coal's Quarterly Report on Form 10-Q filed on August 9, 2016).

Exhibit 10.46 Amendment No. 4, dated as of June 10, 2016, to the Superpriority Secured Debtor-in-Possession Credit Agreement dated January 21, 2016 (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Quarterly Report on Form 10-Q filed on August 9, 2016).

Exhibit 10.47 Amendment No. 5, dated as of June 23, 2016, to the Superpriority Secured Debtor-in-Possession Credit Agreement dated January 21, 2016 (incorporated herein by reference to Exhibit 10.3 to Arch Coal's Quarterly Report on Form 10-Q filed on August 9, 2016).

Exhibit 10.48	Amendment No. 6, dated as of July 20, 2016, to that certain Superpriority Secured Debtor-in-Possession Credit Agreement dated as of January 21, 2016 (incorporated by reference to Exhibit 10.2 of Arch Coal's Current Report on Quarterly Report 10-Q filed on November 9, 2016).
Exhibit 10.49	Amendment No. 7, dated as of September 28, 2016, to the Superpriority Secured Debtor-in-Possession Credit Agreement dated as of January 21, 2016 (incorporated by reference to Exhibit 10.3 of Arch Coal's Current Report on Quarterly Report 10-Q filed on November 9, 2016).
Exhibit 10.50	Restructuring Support Agreement, dated as of January 10, 2016, by and among the Debtors (as defined therein) and the Consenting Lenders (as defined therein) (incorporated herein by reference to Exhibit 10.55 to Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2015).
Exhibit 10.51	Amendment No. 2, dated as of March 28, 2016, to the Restructuring Support Agreement dated January 10, 2016 (incorporated herein by reference to Exhibit 10.2 to Arch Coal's Quarterly Report on Form 10-Q filed on May 10, 2016).
Exhibit 10.52	Amendment No. 3, dated as of April 26, 2016, to the Restructuring Support Agreement dated January 10, 2016 (incorporated herein by reference to Exhibit 10.4 to Arch Coal's Quarterly Report on Form 10-Q filed on August 9, 2016).
Exhibit 10.53	Amendment No. 4, dated as of June 10, 2016, to the Restructuring Support Agreement dated January 10, 2016 (incorporated herein by reference to Exhibit 10.5 to Arch Coal's Quarterly Report on Form 10-Q filed on August 9, 2016).
Exhibit 10.54	Amendment No. 5, dated as of June 23, 2016, to the Restructuring Support Agreement dated January 10, 2016 (incorporated herein by reference to Exhibit 10.6 to Arch Coal's Quarterly Report on Form 10-Q filed on August 9, 2016).
Exhibit 10.55	Amended and Restated Restructuring Support Agreement, dated as of July 5, 2016 (incorporated by reference to Exhibit 10.1 of Arch Coal's Current Report on Quarterly Report 10-Q filed on November 9, 2016).
Exhibit 21.1	Subsidiaries of the registrant.
Exhibit 23.1	Consent of Ernst & Young LLP.
Exhibit 23.2	Consent of Weir International, Inc.
Exhibit 24.1	Power of Attorney
Exhibit 31.1	Rule 13a-14(a)/15d-14(a) Certification of John W. Eaves.
Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of John T. Drexler.
Exhibit 32.1	Section 1350 Certification of John W. Eaves.
Exhibit 32.2	Section 1350 Certification of John T. Drexler.
Exhibit 95.1	Mine Safety Disclosure Exhibit
Exhibit 95.2	Order to Mingo Logan Coal Company, a subsidiary of Arch Coal, Inc. under section 107(a) of the Federal Mine Safety and Health Act of 1977 for excessive measurable limits of methane air mixture (incorporated by reference to Arch Coal's Current Report on Form 8-K filed on September 8, 2016)
Exhibit 101	Interactive Data File (Form 10-K for the year ended December 31, 2016 filed in XBRL). The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed."

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. and subsidiaries (the Company) as of December 31, 2016 (Successor) and 2015 (Predecessor), and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity (deficit) and cash flows for the period from October 2, 2016 through December 31, 2016 (Successor), the period from January 1, 2016 through October 1, 2016 (Predecessor), and for each of the two years in the period ended December 31, 2015 (Predecessor). Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. and subsidiaries at December 31, 2016 (Successor) and 2015 (Predecessor), and the consolidated results of their operations and their cash flows for the period from October 2, 2016 through December 31, 2016 (Successor), the period from January 1, 2016 through October 1, 2016 (Predecessor), and for each of the two years in the period ended December 31, 2015 (Predecessor), in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 3 to the consolidated financial statements, on September 13, 2016, the Bankruptcy Court entered an order confirming the Plan of Reorganization, which became effective on October 5, 2016. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, for the Successor Company as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods (Predecessor) as described in Notes 1 and 3.

/s/ Ernst & Young, LLP

St. Louis, Missouri
February 24, 2017

REPORT OF MANAGEMENT

The management of Arch Coal, Inc. (the "Company") is responsible for the preparation of the consolidated financial statements and related financial information in this annual report. The financial statements are prepared in accordance with accounting principles generally accepted in the United States and necessarily include some amounts that are based on management's informed estimates and judgments, with appropriate consideration given to materiality.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance that financial records are reliable for purposes of preparing financial statements and that assets are properly accounted for and safeguarded. The concept of reasonable assurance is based on the recognition that the cost of a system of internal accounting controls should not exceed the value of the benefits derived. The Company has a professional staff of internal auditors who monitor compliance with and assess the effectiveness of the system of internal accounting controls.

The Audit Committee of the Board of Directors, comprised of independent directors, meets regularly with management, the internal auditors, and the independent auditors to discuss matters relating to financial reporting, internal accounting control, and the nature, extent and results of the audit effort. The independent auditors and internal auditors have full and free access to the Audit Committee, with and without management present.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Arch Coal, Inc. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Securities Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process designed under the supervision of our principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

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

Under the supervision and with the participation of the Company's management, including its principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting as of December 31, 2016 based on the criteria set forth in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, management concluded that the Company's internal control over financial reporting is effective as of December 31, 2016.

Arch Coal, Inc. and Subsidiaries
Consolidated Statements of Operations
(in thousands, except per share data)

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues	$ 575,688	$ 1,398,709	$ 2,573,260	$ 2,937,119
Costs, expenses and other operating				
Cost of sales (exclusive of items shown separately below)	470,644	1,264,464	2,172,753	2,533,284
Depreciation, depletion and amortization	32,604	191,581	379,345	418,748
Accretion on asset retirement obligations	7,634	24,321	33,680	32,909
Amortization of sales contracts, net	796	(728)	(8,811)	(13,187)
Change in fair value of coal derivatives and coal trading activities, net	396	2,856	(1,583)	(3,686)
Asset impairment and mine closure costs	—	129,267	2,628,303	24,113
Losses from disposed operations resulting from Patriot Coal bankruptcy	—	—	116,343	—
Selling, general and administrative expenses	22,836	59,343	98,783	114,223
Other operating expense (income), net	(5,340)	(15,257)	19,510	(19,754)
	529,570	1,655,847	5,438,323	3,086,650
Income (loss) from operations	46,118	(257,138)	(2,865,063)	(149,531)
Interest expense, net				
Interest expense	(11,241)	(135,888)	(397,979)	(390,946)
Interest and investment income	487	2,653	4,430	7,758
	(10,754)	(133,235)	(393,549)	(383,188)
Income (loss) before nonoperating expenses	35,364	(390,373)	(3,258,612)	(532,719)
Nonoperating expense				
Net loss resulting from early retirement of debt and debt restructuring	—	(2,213)	(27,910)	—
Reorganization income (loss), net	(759)	1,630,041	—	—
	(759)	1,627,828	(27,910)	—
Income (loss) before income taxes	34,605	1,237,455	(3,286,522)	(532,719)
Provision for (benefit from) income taxes	1,156	(4,626)	(373,380)	25,634
Net income (loss)	33,449	1,242,081	(2,913,142)	(558,353)
Earnings per common share				
Basic earnings per common share	$ 1.34	$ 58.33	$ (136.86)	$ (26.31)
Diluted earnings per common share	$ 1.31	$ 58.28	$ (136.86)	$ (26.31)
Weighted average shares outstanding				
Basic weighted average shares outstanding	25,002	21,293	21,285	21,222
Diluted weighted average shares outstanding	25,469	21,313	21,285	21,222

The accompanying notes are an integral part of the consolidated financial statements.

Arch Coal, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Net income (loss)	$ 33,449	$ 1,242,081	$ (2,913,142)	$ (558,353)
Derivative instruments				
Comprehensive income (loss) before tax	—	(532)	(3,477)	3,102
Income tax benefit (provision)	—	80	1,252	(1,117)
	—	(452)	(2,225)	1,985
Pension, postretirement and other post-employment benefits				
Comprehensive income (loss) before tax	24,067	(1,848)	(5,592)	(44,143)
Income tax benefit (provision)	—	483	2,011	15,891
	24,067	(1,365)	(3,581)	(28,252)
Available-for-sale securities				
Comprehensive income (loss) before tax	387	2,968	1,185	(12,788)
Income tax benefit (provision)	—	(1,042)	(435)	4,604
	387	1,926	750	(8,184)
Total other comprehensive income (loss)	24,454	109	(5,056)	(34,451)
Total comprehensive income (loss)	$ 57,903	$ 1,242,190	$ (2,918,198)	$ (592,804)

The accompanying notes are an integral part of the consolidated financial statements.

Arch Coal, Inc. and Subsidiaries
Consolidated Balance Sheets
(in thousands, except per share data)

	Successor December 31, 2016	Predecessor December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$ 305,372	$ 450,781
Short term investments	88,072	200,192
Restricted cash	71,050	97,542
Trade accounts receivable (net of allowance for doubtful accounts of $0.0 million and $7.8 million, respectively)	184,483	117,405
Other receivables	19,877	18,362
Inventories	113,462	196,720
Prepaid royalties	2,281	10,022
Deferred income taxes	—	—
Coal derivative assets	262	8,035
Other current assets	93,763	39,866
Total current assets	878,622	1,138,925
Property, plant and equipment		
Coal lands and mineral rights	387,591	3,713,639
Plant and equipment	418,182	2,359,674
Deferred mine development	280,323	553,286
	1,086,096	6,626,599
Less accumulated depreciation, depletion and amortization	(32,493)	(3,007,570)
Property, plant and equipment, net	1,053,603	3,619,029
Other assets		
Prepaid royalties	—	23,671
Equity investments	96,074	201,877
Other noncurrent assets	108,298	58,379
Total other assets	204,372	283,927
Total assets	$ 2,136,597	$ 5,041,881
Liabilities and Stockholders' Equity (Deficit)		
Current liabilities		
Accounts payable	$ 95,953	$ 128,131
Accrued expenses and other current liabilities	205,240	329,450
Current maturities of debt	11,038	5,042,353
Total current liabilities	312,231	5,499,934
Long-term debt	351,841	30,953
Asset retirement obligations	337,227	396,659
Accrued pension benefits	38,884	27,373
Accrued postretirement benefits other than pension	101,445	99,810
Accrued workers’ compensation	184,568	112,270
Other noncurrent liabilities	63,824	119,171
Total liabilities	1,390,020	6,286,170
Stockholders' equity (deficit)		
Successor Common stock, $0.01 par value, authorized 300,000 shares, issued 25,002 shares at December 31, 2016	250	—
Predecessor Common stock, $0.01 par value, authorized 26,000 shares, issued 21,446 shares at December 31, 2015	—	2,145
Paid-in capital	688,424	3,054,211
Treasury stock, at cost	—	(53,863)
Retained earnings (accumulated deficit)	33,449	(4,244,967)
Accumulated other comprehensive income (loss)	24,454	(1,815)

Total stockholders' equity (deficit)	746,577	(1,244,289)
Total liabilities and stockholders' equity (deficit)	$ 2,136,597	$ 5,041,881

The accompanying notes are an integral part of the consolidated financial statements.

Arch Coal, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(in thousands)

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Operating activities				
Net income (loss)	$ 33,449	$ 1,242,081	$ (2,913,142)	$ (558,353)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	32,604	191,581	379,345	418,748
Accretion on asset retirement obligations	7,634	24,321	33,680	32,909
Amortization of sales contracts, net	796	(728)	(8,811)	(13,187)
Prepaid royalties expensed	2,587	4,791	8,109	9,698
Deferred income taxes	3	(419)	(367,210)	25,152
Employee stock-based compensation expense	1,032	2,096	5,760	9,847
Gains on disposals and divestitures	(485)	(6,628)	(2,270)	(27,512)
Asset impairment and noncash mine closure costs	—	119,194	2,613,345	16,868
Losses from disposed operations resulting from Patriot Coal bankruptcy	—	—	116,343	—
Amortization relating to financing activities	467	12,800	25,241	17,363
Net loss resulting from early retirement of debt and debt restructuring	—	2,213	27,910	—
Non-cash bankruptcy reorganization items	—	(1,775,910)	—	—
Changes in:				
Receivables	(22,196)	(42,786)	98,212	(8,991)
Inventories	24,870	34,440	(6,534)	41,548
Coal derivative assets and liabilities	1,662	5,678	973	5,449
Accounts payable, accrued expenses and other current liabilities	34,129	15,316	(15,532)	41,680
Asset retirement obligations	(4,535)	(12,041)	(17,040)	(14,621)
Pension, postretirement and other postemployment benefits	(5,625)	(15,692)	4,800	(25,347)
Other	(22,200)	(28,525)	(27,546)	(4,833)
Cash provided by (used in) operating activities	84,192	(228,218)	(44,367)	(33,582)
Investing activities				
Capital expenditures	(15,214)	(82,434)	(119,024)	(147,286)
Minimum royalty payments	(63)	(305)	(5,871)	(7,317)
Proceeds from disposals and divestitures	572	(2,921)	2,191	62,358
Purchases of short term investments	—	(98,750)	(246,735)	(211,929)
Proceeds from sales of short term investments	23,000	185,859	290,205	205,611
Proceeds from sale of investments in equity investments and securities	—	1,147	2,259	9,464
Investments in and advances to affiliates, net	(823)	(3,441)	(11,502)	(16,657)
Withdrawals (deposits) of restricted cash	10,512	15,979	(91,864)	(5,678)
Cash provided by (used in) investing activities	17,984	15,134	(180,341)	(111,434)
Financing activities				
Payments to retire debt	—	—	—	(300)
Payments on term loan	(816)	—	(19,500)	(19,500)
Net receipts (payments) on other debt	3,374	(11,986)	(11,332)	(5,395)
Debt financing costs	—	(23,011)	—	(4,519)
Dividends paid	—	—	—	(2,123)
Expenses related to debt restructuring	—	(2,213)	(27,910)	—
Other	151	—	—	(15)
Cash provided by (used in) financing activities	2,709	(37,210)	(58,742)	(31,852)
Increase (decrease) in cash and cash equivalents	104,885	(250,294)	(283,450)	(176,868)
Cash and cash equivalents, beginning of period	200,487	450,781	734,231	911,099
Cash and cash equivalents, end of period	$ 305,372	$ 200,487	$ 450,781	$ 734,231
SUPPLEMENTAL CASH FLOW INFORMATION				
Cash paid during the period for interest	$ 39,620	$ 79,979	$ 283,337	$ 361,727
Cash refunded during the period for income taxes, net	$ 287	$ 49	$ 4,138	$ 4,896

The accompanying notes are an integral part of the consolidated financial statements.

Arch Coal, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity (Deficit)
Three Years Ended December 31, 2016

	Common Stock	Paid-In Capital	Treasury Stock, at Cost	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	(In thousands, except per share data)					
Predecessor Company						
BALANCE AT JANUARY 1, 2014	$ 2,141	$ 3,038,613	$ (53,848)	$ (771,349)	$ 37,692	$ 2,253,249
Total comprehensive loss	—	—	—	(558,353)	(34,451)	(592,804)
Dividends on common shares ($0.01 per share)	0	0	—	(2,123)	—	(2,123)
Treasury shares purchased	—	—	(15)	—	—	(15)
Employee stock-based compensation expense	—	9,847	—	—	—	9,847
BALANCE AT DECEMBER 31, 2014	$ 2,141	$ 3,048,460	$ (53,863)	$ (1,331,825)	$ 3,241	$ 1,668,154
Total comprehensive loss	0	0	—	(2,913,142)	(5,056)	(2,918,198)
Issuance of 64 shares of common stock under the stock incentive plan-restricted stock and restricted stock units, net of forfeitures	4	(9)	—	—	—	(5)
Employee stock-based compensation expense	—	5,760	—	—	—	5,760
BALANCE AT DECEMBER 31, 2015	$ 2,145	$ 3,054,211	$ (53,863)	$ (4,244,967)	$ (1,815)	$ (1,244,289)
Total comprehensive income	—	—	—	1,242,081	109	1,242,190
Employee stock-based compensation	—	2,099	—	—	—	2,099
Elimination of predecessor equity	(2,145)	(3,056,310)	53,863	3,002,886	1,706	—
BALANCE AT OCTOBER 1, 2016	$ —	$ —	$ —	$ —	$ —	$ —
Successor Company						
Issuance of successor equity	$ 250	$ 687,233	$ —	$ —	$ —	$ 687,483
Employee stock-based compensation	—	1,032	—	—	—	1,032
Warrants exercised	—	159	—	—	—	159
Total comprehensive income	—	—	—	33,449	24,454	57,903
BALANCE AT DECEMBER 31, 2016	$ 250	$ 688,424	$ —	$ 33,449	$ 24,454	$ 746,577

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

1. **Basis of Presentation**

The accompanying consolidated financial statements include the accounts of Arch Coal, Inc. and its subsidiaries and controlled entities (the "Company"). Unless the context indicates otherwise, the terms "Arch" and the "Company" are used interchangeably in this Annual Report on Form 10-K refer to both the Predecessor and Successor Company. The Company's primary business is the production of thermal and metallurgical coal from surface and underground mines located throughout the United States, for sale to utility, industrial and steel producers both in the United States and around the world. The Company currently operates mining complexes in West Virginia, Kentucky, Virginia, Illinois, Wyoming and Colorado. All subsidiaries are wholly-owned. Intercompany transactions and accounts have been eliminated in consolidation.

Chapter 11 Filing and Emergence from Bankruptcy

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.

For periods subsequent to filing the Bankruptcy Petitions, the Company applied the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852, "Reorganizations", in preparing its consolidated financial statements. ASC 852 requires that financial statements distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that are realized or incurred in the bankruptcy proceedings have been recorded in a reorganization line item on the Consolidated Statement of Operations. In addition, the pre-petition obligations that may be impacted by the bankruptcy reorganization process were classified on the balance sheet as liabilities subject to compromise.

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.

On October 5, 2016, Arch Coal satisfied the closing conditions contemplated by the Plan, which became effective on that date (the "Effective Date").

On the Plan Effective Date, the Company applied fresh start accounting which requires the Company to allocate its reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. In addition to fresh start accounting, the Company's 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. The Company 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, the Company's financial statements for the Successor will not be comparable in many respects to its financial statements for periods prior to the adoption of fresh start accounting and prior to the accounting for the effects of the Plan. For further information on fresh start accounting, please see Note 3 to the Consolidated Financial Statements, "Emergence from Bankruptcy and Fresh Start Accounting."

2. **Accounting Policies**

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States for financial reporting and U.S. Securities and Exchange Commission regulations.

Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and revenues and expenses in the accompanying consolidated financial statements and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost. Cash equivalents consist of highly-liquid investments with an original maturity of three months or less when purchased.

Restricted cash

Restricted cash represents cash collateral supporting letters of credit issued under the Company's accounts receivable securitization program.

Accounts Receivable

Accounts receivable are recorded at amounts that are expected to be collected, based on past collection history, the economic environment and specified risks identified in the receivables portfolio.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs, transportation costs incurred prior to the transfer of title to customers and operating overhead. The costs of removing overburden, called stripping costs, incurred during the production phase of the mine are considered variable production costs and are included in the cost of the coal extracted during the period the stripping costs are incurred.

Investments and Membership Interests in Joint Ventures

Investments and membership interests in joint ventures are accounted for under the equity method of accounting if the Company has the ability to exercise significant influence, but not control, over the entity. The Company's share of the entity's income or loss is reflected in "Other operating expense (income), net" in the consolidated statements of operations. Information about investment activity is provided in Note 9 to the Consolidated Financial Statements, "Equity Method Investments and Membership Interests in Joint Ventures."

Investments in debt securities and marketable equity securities that do not qualify for equity method accounting are classified as available-for-sale and are recorded at their fair values. Unrealized gains and losses on these investments are recorded in other comprehensive income or loss. A decline in the value of an investment that is considered other-than-temporary would be recognized in operating expenses.

Sales Contracts

Coal supply agreements (sales contracts) valued during fresh start accounting or acquired in a business combination are capitalized at their fair value and amortized over the tons of coal shipped during the term of the contract. The fair value of a sales contract is determined by discounting the cash flows attributable to the difference between the contract price and the prevailing forward prices for the tons under contract at the date of acquisition. See Note 10 to the Consolidated Financial Statements, "Sales Contracts" for further information related to the Company's sales contracts.

Exploration Costs

Costs to acquire permits for exploration activities are capitalized. Drilling and other costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred.

Prepaid Royalties

Leased mineral rights are often acquired through royalty payments. When royalty payments represent prepayments recoupable against royalties owed on future revenues from the underlying coal, they are recorded as a prepaid asset, with amounts expected to be recouped within one year classified as current. When coal from these leases is sold, the royalties owed are recouped against the prepayment and charged to cost of sales. An impairment charge is recognized for prepaid royalties that are not expected to be recouped.

Property, Plant and Equipment

Plant and Equipment

Plant and equipment were fair valued at emergence during fresh start accounting; subsequent purchases of property, plant and equipment have been recorded at cost. Interest costs incurred during the construction period for major asset additions are capitalized. The Company did not capitalize any interest costs during the periods October 2 through December 31, 2016, January 1 through October 1, 2016 or for the year ended December 31, 2015, respectively. Expenditures that extend the useful lives of existing plant and equipment or increase the productivity of the asset are capitalized. The cost of maintenance and repairs that do not extend the useful life or increase the productivity of the asset is expensed as incurred.

Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation. Other plant and equipment are depreciated principally using the straight-line method over the estimated useful lives of the assets, limited by the remaining life of the mine. The useful lives of mining equipment, including longwalls, draglines and shovels, range from 7 to 18 years. The useful lives of buildings and leasehold improvements generally range from 1 to 18 years.

Deferred Mine Development

Costs of developing new mines or significantly expanding the capacity of existing mines are capitalized and amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited. Costs may include construction permits and licenses; mine design; construction of access roads, shafts, slopes and main entries; and removing overburden to access reserves in a new pit. Additionally, deferred mine development includes the asset cost associated with asset retirement obligations.

Coal Lands and Mineral Rights

Rights to coal reserves may be acquired directly through governmental or private entities. A significant portion of the Company’s coal reserves are controlled through leasing arrangements. Lease agreements are generally long-term in nature (original terms range from 10 to 50 years), and substantially all of the leases contain provisions that allow for automatic extension of the lease term providing certain requirements are met.

The net book value of the Company’s coal interests was $0.4 billion and $2.4 billion at December 31, 2016 and 2015, respectively. Payments to acquire royalty lease agreements and lease bonus payments are capitalized as a cost of the underlying mineral reserves and depleted over the life of proven and probable reserves. Coal lease rights are depleted using the units-of-production method, and the rights are assumed to have no residual value.

The Company currently does not have any future lease bonus payments.

Depreciation, depletion and amortization

The depreciation, depletion and amortization related to long-lived assets is reflected in the statement of operations as a separate line item. No depreciation, depletion or amortization is included in any other operating cost categories.

Impairment

If facts and circumstances suggest that the carrying value of a long-lived asset or asset group may not be recoverable, the asset or asset group is reviewed for potential impairment. If this review indicates that the carrying amount of the asset will not be recoverable through projected undiscounted cash flows generated by the asset and its related asset group over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its fair value. The Company may, under certain circumstances, idle mining operations in response to market conditions or other factors. Because an idling is not a permanent closure, it is not considered an automatic indicator of impairment. See additional discussion in Note 5 to the Consolidated Financial Statements, “Impairment Charges and Mine Closure Costs.”

Deferred Financing Costs

The Company capitalizes costs incurred in connection with new borrowings, the establishment or enhancement of credit facilities and the issuance of debt securities. These costs are amortized as an adjustment to interest expense over the life of the borrowing or term of the credit facility using the interest method. Debt issuance costs related to a recognized liability are presented in the balance sheet as a direct reduction from the carrying amount of that liability whereas debt issuance costs related to a credit facility with no balance outstanding are shown as an asset. The unamortized balance of deferred financing costs was $5.2 million at December 31, 2016, with $1.9 million classified as current. As these amounts relate to a credit facility with no outstanding borrowings, these current amounts are classified within “Other current assets” and the noncurrent amounts are classified within “Other noncurrent assets.” The unamortized balance of deferred financing costs at December 31, 2015 was $66.3 million with $65.6 million classified as current. As these debt issuance costs primarily related to a recognized liability, the current amounts are recorded in “Current maturities of debt” and the noncurrent amounts are recorded in “Long-term debt” in the accompanying consolidated balance sheets.

Revenue Recognition

Revenues include sales to customers of coal produced at Company operations and coal purchased from third parties. The Company recognizes revenue at the time risk of loss passes to the customer at contracted amounts. Transportation costs are included in cost of sales and amounts billed by the Company to its customers for transportation are included in revenues.

Other Operating Expense (Income), net

Other operating expense (income), net in the accompanying consolidated statements of operations reflects income and expense from sources other than physical coal sales, including: bookouts, or the practice of offsetting purchase and sale contracts for shipping convenience purposes; contract settlements; liquidated damage charges related to unused terminal and port capacity; royalties earned from properties leased to third parties; income from equity investments (Note 9); gains and losses from divestitures and dispositions of assets; and realized gains and losses on derivatives that do not qualify for hedge accounting and are not held for trading purposes (Note 11).

Asset Retirement Obligations

The Company's legal obligations associated with the retirement of long-lived assets are recognized at fair value at the time the obligations are incurred. Accretion expense is recognized through the expected settlement date of the obligation. Obligations are incurred at the time development of a mine commences for underground and surface mines or construction begins for support facilities, refuse areas and slurry ponds. The obligation's fair value is determined using a discounted cash flow technique and is based upon permit requirements and various estimates and assumptions that would be used by market participants, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset.

The Company reviews its asset retirement obligation at least annually and makes necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of the amount and timing of costs. For ongoing operations, adjustments to the liability result in an adjustment to the corresponding asset. For idle operations, adjustments to the liability are recognized as income or expense in the period the adjustment is recorded. Any difference between the recorded obligation and the actual cost of reclamation is recorded in profit or loss in the period the obligation is settled. See additional discussion in Note 15, "Asset Retirement Obligations."

Loss Contingencies

The Company accrues for cost related to contingencies when a loss is probable and the amount is reasonably determinable. Disclosure of contingencies is included in the financial statements when it is at least reasonably possible that a material loss or an additional material loss in excess of amounts already accrued may be incurred. The amount accrued represents the Company's best estimate of the loss, or, if no best estimate within a range of outcomes exists, the minimum amount in the range.

Derivative Instruments

The Company generally utilizes derivative instruments to manage exposures to commodity prices. Additionally, the Company may hold certain coal derivative instruments for trading purposes. Derivative financial instruments are recognized in the balance sheet at fair value. Certain coal contracts may meet the definition of a derivative instrument, but because they provide for the physical purchase or sale of coal in quantities expected to be used or sold by the Company over a reasonable period in the normal course of business, they are not recognized on the balance sheet.

Certain derivative instruments are designated as the hedge instrument in a hedging relationship. In a fair value hedge, the Company hedges the risk of changes in the fair value of a firm commitment, typically a fixed-price coal sales contract. Changes in both the hedged firm commitment and the fair value of a derivative used as a hedge instrument in a fair value hedge are recorded in earnings. In a cash flow hedge, the Company hedges the risk of changes in future cash flows related to a forecasted purchase or sale. Changes in the fair value of the derivative instrument used as a hedge instrument in a cash flow hedge are recorded in other comprehensive income or loss. Amounts in other comprehensive income or loss are reclassified to earnings when the hedged transaction affects earnings and are classified in a manner consistent with the transaction being hedged. The Company formally documents the relationships between hedging instruments and the respective hedged items, as well as its risk management objectives for hedge transactions.

The Company evaluates the effectiveness of its hedging relationships both at the hedge's inception and on an ongoing basis. Any ineffective portion of the change in fair value of a derivative instrument used as a hedge instrument in a fair value or cash flow hedge is recognized immediately in earnings. The ineffective portion is based on the extent to which exact offset is not achieved between the change in fair value of the hedge instrument and the cumulative change in expected future cash flows on the hedged transaction from inception of the hedge in a cash flow hedge or the change in the fair value. Ineffectiveness was insignificant for the periods disclosed within.

See Note 11, “Derivatives” for further disclosures related to the Company’s derivative instruments.

Fair Value

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly hypothetical transaction between market participants at a given measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs. See Note 16, “Fair Value Measurements” for further disclosures related to the Company’s recurring fair value estimates.

Income Taxes

Deferred income taxes are provided for temporary differences arising from differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates anticipated to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. Management reassesses the ability to realize its deferred tax assets annually in the fourth quarter or when circumstances indicate that the ability to realize deferred tax assets has changed. In determining the need for a valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies and the reversal of temporary differences.

Benefits from tax positions that are uncertain are not recognized unless the Company concludes that it is more likely than not that the position would be sustained in a dispute with taxing authorities, should the dispute be taken to the court of last resort. The Company would measure any such benefit at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement with taxing authorities.

See Note 14, “Taxes” for further disclosures about income taxes.

Benefit Plans

The Company has non-contributory defined benefit pension plans covering most of its salaried and hourly employees. On January 1, 2015 the Company’s cash balance and excess pension plans were amended to freeze new service credits for any new or active employee. The Company also currently provides certain postretirement medical and life insurance coverage for eligible employees. The cost of providing these benefits are determined on an actuarial basis and accrued over the employee’s period of active service.

The Company recognizes the overfunded or underfunded status of these plans as determined on an actuarial basis on the balance sheet and the changes in the funded status are recognized in other comprehensive income. The Company amortizes actuarial gains and losses over the remaining service attribution periods of the employees using the corridor method. See Note 20, “Employee Benefit Plans” for additional disclosures relating to these obligations.

Stock-Based Compensation

The compensation cost of all stock-based awards is determined based on the grant-date fair value of the award, and is recognized over the requisite service period. The grant-date fair value of option awards and restricted stock awards with a market condition is determined using a Monte Carlo simulation. Compensation cost for an award with performance conditions is accrued if it is probable that the conditions will be met. See further discussion in Note 18, “Stock-Based Compensation and Other Incentive Plans.”

Recently Adopted Accounting Guidance

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03 (“ASU 2015-03”), Simplifying the Presentation of Debt Issuance Costs. ASU 2015-03 required debt issuance costs related to a recognized liability to be presented in the balance sheet as a direct reduction from the carrying amount of that liability, consistent with debt discounts. The Company adopted ASU 2015-03 in the first quarter of 2016 as mandated by the standard. The following reflects the retrospective application:

	December 31, 2015 (in thousands)
Other current assets, prior to revision	$ 104,723
Revision of debt issuance costs	(64,857)
Other current assets, as revised	$ 39,866
Current maturities of debt, prior to revision	$ 5,107,210
Revision of debt issuance costs	(64,857)
Current maturities of debt, as revised	$ 5,042,353

Effective December 31, 2016, the Company adopted ASU No. 2014-15 (“ASU 2014-15”), Disclosures of Uncertainties about an Entity’s Ability to Continue as a Going Concern. ASU 2014-15 requires management to evaluate for each annual and interim reporting period whether conditions or events give rise to substantial doubt that an entity has the ability to continue as a going concern within one year following issuance of the financial statements and requires specific disclosures regarding the conditions or events leading to substantial doubt. The adoption of ASU 2014-15 did not have any impact on the Company’s financial position or results of operations.

Effective December 31, 2016, the Company adopted the Accounting Standards Update No. 2015-17 (“ASU 2015-17”), Balance Sheet Classification of Deferred Taxes which requires that all deferred tax assets and liabilities, along with any related valuation allowance be classified as noncurrent on the balance sheet. The standard has been applied on a retrospective basis. The adoption of ASU 2015-17 did not have any impact on the Company’s financial position or results of operations.

Investments at fair value include investments in funds, including certain money market funds, that are measured at net asset value (“NAV”). The Company uses NAV to measure the fair value of its fund investments when (i) the fund investment does not have a readily determinable fair value and (ii) the NAV of the investment fund is calculated in a manner consistent with the measurement principles of investment company accounting, including measurement of the underlying investments at fair value. The Company adopted ASU No. 2015-07 in January 2016, and, as required, disclosures in the paragraphs and tables below are limited to only those investments in funds that are measured at NAV. In accordance with ASU No. 2015-07, previously reported amounts have been conformed to the current presentation.

Recent Accounting Guidance Issued Not Yet Effective

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers.” ASU 2014-09 is a comprehensive revenue recognition standard that will supersede nearly all existing revenue recognition guidance under current U.S. GAAP and replace it with a principle based approach for determining revenue recognition. ASU 2014-09 will require that companies recognize revenue based on the value of transferred goods or services as they occur in the contract. The ASU also will require additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. ASU 2014-09 is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted only in annual reporting periods beginning after December 15, 2016, including interim periods therein. Entities will be able to transition to the standard either retrospectively or as a cumulative-effect adjustment as of the date of adoption. The Company’s primary source of revenue is from the sale of coal through both short-term and long-term contracts with utilities, industrial customers and steel producers whereby revenue is currently recognized when risk of loss has passed to the customer. Upon adoption of this new standard, the Company believes that the timing of revenue recognition related to our coal sales will remain consistent with our current practice. The Company is currently evaluating other revenue streams to determine the potential impact related to the adoption of the standard, as well as potential disclosures required by the standard. The Company will be adopting the standard under the modified retrospective approach.

In February 2016, the FASB issued ASU No. 2016-02, “Leases” which, for operating leases, requires a lessee to recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, in its balance sheet. The standard also requires a lessee to recognize a single lease cost, calculated so that the cost of the lease is allocated over the term of the lease, on a generally straight line basis. The ASU is effective for public companies for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early adoption is permitted. The Company has both operating and capital leases. We expect the adoption of this standard to result in the recognition of right-of-use assets and lease liabilities not currently recorded on the Company’s financial statements. The Company is currently in the process of accumulating all contractual lease arrangements in order to determine the impact on its financial statements.

In October 2016, the FASB issued ASU No. 2016-18, “Statement of Cash Flows-Restricted Cash.” The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning period and end of period total amounts shown on the statement of cash flows. ASU 2016-18 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early adoption is permitted.

3. Emergence from Bankruptcy and Fresh Start Accounting

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.

For periods subsequent to filing the Bankruptcy Petitions, the Company applied the FASB Accounting Standards Codification ("ASC") 852, "Reorganizations", in preparing its consolidated financial statements. ASC 852 requires that financial statements distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that are realized or incurred in the bankruptcy proceedings have been recorded in a reorganization line item on the Consolidated Statement of Operations. In addition, the pre-petition obligations that may be impacted by the bankruptcy reorganization process were classified on the balance sheet as liabilities subject to compromise.

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.

On October 5, 2016, Arch Coal satisfied the closing conditions contemplated by the Plan, which became effective on that date (the "Effective Date").

On the Plan Effective Date, the Company applied fresh start accounting which requires the Company to allocate its reorganization value to the fair value of assets and liabilities in conformity with the guidance for the acquisition method of accounting for business combinations. In addition to fresh start accounting, the Company's 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. The Company 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, the Company's financial statements for the Successor will not be comparable in many respects to its financial statements for periods prior to the adoption of fresh start accounting and prior to the accounting for the effects of the Plan.

The following is a summary of certain provisions of the Plan, as confirmed by the Bankruptcy Court pursuant to the Confirmation Order, and is not intended to be a complete description of the Plan.

Treatment of Claims

The Plan contemplates that:

- Holders of allowed administrative expense claims, priority claims (other than administrative expense claims and priority tax claims) and secured claims (other than claims arising under priority claims, the prepetition first lien credit facility and prepetition second lien notes) will be paid in full.

- Holders of allowed claims arising under the Debtors' prepetition first lien credit facility ("First Lien Credit Facility") will receive their pro rata distribution of (i) total cash payments equal to the greater of (A) $144.8 million less the amount of the adequate protection payments and (B) $30 million; (ii) $326.5 million in principal amount of New First Lien Debt Facility; and (iii) 94% of the common stock of Reorganized Arch Coal (the "New Common Stock"), subject to dilution on account of (a) any Class A Common Stock (as defined below) issued upon exercise of the warrants (the "New Warrants") issued pursuant to the Plan to purchase up to 12% of the fully diluted Class A Common Stock as of the Effective Date and exercisable at any time for a period of 7 years from the Effective Date at a strike price calculated based on a total equity capitalization of $1.425 billion ($57 per share) and (b) the issuance of New Common

Stock in an amount of up to 10% of the New Common Stock, on a fully diluted basis, pursuant to a management incentive plan (the "Management Incentive Plan").

- Holders of allowed claims on account of prepetition second lien or unsecured notes (the "Prepetition Notes") will receive their pro rata distribution of (i) $22.636 million in cash, (ii) at such holder's election, either (A) such holder's pro rata share of the New Warrants or (B) such holder's pro rata share of $25 million in cash and (iii) 6% of the New Common Stock (subject to dilution on account of any exercise of the New Warrants and pursuant to the Management Incentive Plan).

- Holders of allowed general unsecured claims against Debtors (other than claims on account of the First Lien Credit Facility or Prepetition Notes) will receive their pro rata distribution of $7.364 million cash, less fees and expenses incurred by any professionals retained by a claims oversight committee up to $200,000.

- The Reorganized Debtors will waive and release any claims or causes of action that they have, had, or may have that are based on sections 502(d), 544, 545, 547, 548, 549, 550, 551, 553(b) and 724(a) of the Bankruptcy Code and analogous non-bankruptcy law for all purposes against (i) prepetition trade creditors and (ii) officers, directors, employees or representatives of the Debtors or the Reorganized Debtors and all agents and representatives of all of the foregoing. However, the Reorganized Debtors will retain the right to assert any said claims as defenses or counterclaims in any cause of action brought by any creditor.

New First Lien Debt Facility

For information related to the New First Lien Debt Facility, see Note 13, "Debt and Financing Arrangements."

Securitization Facility

For information related to the Securitization Facility, see Note 13, "Debt and Financing Arrangements."

Warrant Agreement

On the Effective Date, the Company entered into a warrant agreement (the "Warrant Agreement") with American Stock Transfer & Trust Company, LLC as warrant agent and, pursuant to the terms of the Plan, issued warrants ("Warrants") to purchase up to an aggregate of 1,914,856 shares of Class A Common Stock, par value $0.01 per share, of Arch Coal (the "Class A Common Stock") to holders of claims arising under the Cancelled Notes (as defined below). Each Warrant expires on October 5, 2023, and is initially exercisable for one share of Class A Common Stock at an initial exercise price of $57.00 per share. The Warrants are exercisable by a holder paying the exercise price in cash or on a cashless basis, at the election of the holder. The Warrants contain anti-dilution adjustments for stock splits, reverse stock splits, stock dividends, dividends and distributions of cash, other securities or other property, spin-offs and tender and exchange offers by Arch Coal or its subsidiaries to purchase Class A Common Stock at above-market prices.

If, in connection with a merger, recapitalization, business combination, transfer to a third party of substantially all of Arch Coal's consolidated assets or other transaction that results in a change to the Class A Common Stock (each, a "Transaction"), (i) the Transaction is consummated prior to the fifth anniversary of the Effective Date and the Transaction consideration to holders of Class A Common Stock is 90% or more listed common stock or common stock of a company that provides publicly available financial reporting, and holds management calls regarding the same, no less than quarterly ("Reporting Stock") or (ii) regardless of the consideration, the Transaction is consummated on or after the fifth anniversary of the Effective Date, the Warrants will be assumed by the surviving company and will become exercisable for the consideration that the holders of Class A Common Stock receive in such Transaction; *provided* that if the consideration such holders receive consists solely of cash, then upon the consummation of such Transaction, Arch Coal will pay for each Warrant an amount of cash equal to the greater of (i) (x) the amount of cash payable with respect to the number of shares of Class A Common Stock underlying the Warrant *minus* (y) the exercise price per share then in effect *multiplied by* the number of shares of Class A Common Stock underlying the Warrant and (ii) $0.

If a Transaction is consummated prior to the fifth anniversary of the Effective Date in which the Transaction consideration is less than 90% Reporting Stock, a portion of the Warrants corresponding to the portion of the Transaction consideration that is Reporting Stock will be assumed by the surviving company and will become exercisable for the Reporting Stock consideration that the holders of Class A Common Stock receive in such Transaction, and the portion of the Warrants corresponding to the portion of the Transaction consideration that is not Reporting Stock will, at the option of each holder, (i) be assumed by the surviving company and will become exercisable for the consideration that the holders of Class A Common Stock receive in such Transaction or (ii) be redeemed by Arch Coal for cash in an amount equal to the Black Scholes Payment (as defined in the Warrant Agreement).

Termination of Material Definitive Agreements

On the Effective Date, by operation of the Plan, all outstanding obligations under the following notes issued by Arch Coal and guaranteed by certain subsidiary guarantors, (collectively, the "Cancelled Notes") were cancelled and the indentures governing such obligations were cancelled except as necessary to (a) enforce the rights, claims and interests of the applicable trustee vis-a-vis any parties other than the Debtors, (b) allow each trustee to receive distributions under the Plan and to distribute them to the holders of the Cancelled Notes in accordance with the terms of the applicable indenture, (c) preserve any rights of the applicable trustee to compensation, reimbursement and indemnification under each of the applicable indentures solely as against any money or property distributable to holders of Cancelled Notes, (iv) permit each of the trustees to enforce any obligation owed to them under the Plan and (v) permit each of the trustees to appear in the Chapter 11 cases or in any proceeding in the Bankruptcy Court or any other court:

- 7.000% Senior Notes due 2019, issued pursuant to an indenture dated as of June 14, 2011, by and among Arch Coal, as issuer, UMB Bank National Association, as trustee, and the guarantors named therein, as amended, supplemented or revised thereafter;

- 7.250% Senior Notes due 2020, issued pursuant to an indenture dated as of August 9, 2010, by and among Arch Coal, as issuer, U.S. Bank National Association, as trustee, and the guarantors named therein, as amended, supplemented or revised thereafter;

- 7.250% Senior Notes due 2021, issued pursuant to an indenture dated as of June 14, 2011, by and among Arch Coal, as issuer, UMB Bank National Association, as trustee, and the guarantors named therein, as amended, supplemented or revised thereafter;

- 9.875% Senior Notes due 2019, issued pursuant to an indenture dated as of November 21, 2012, by and among Arch Coal, as issuer, UMB Bank National Association, as trustee, and the guarantors named therein, as amended, supplemented or revised thereafter; and

- 8.000% Second Lien notes due 2019, issued pursuant to an indenture dated as of December 17, 2013, by and among Arch Coal, as issuer, Wilmington Savings Fund Society, as trustee and collateral agent as successor to UMB Bank National Association, and the guarantors named therein, as amended, supplemented or revised thereafter.

On the Effective Date, by operation of the Plan, all outstanding obligations under the following credit agreement (the "Prepetition Credit Agreement") entered into by Arch Coal and guaranteed by certain of Arch Coal's subsidiaries and the related collateral, guaranty and other definitive agreements relating to the Prepetition Credit Agreement were cancelled and the Prepetition Credit Agreement was cancelled except as necessary to (i) enforce the rights, claims and interests of the Prepetition Agent (as defined below) and any predecessor thereof vis-a-vis the Lenders and any parties other than the Debtors, (ii) to allow the Prepetition Agent to receive distributions under the Plan and to distribute them to the lenders under the Prepetition Credit Agreement and (iii) preserve any rights of the Prepetition Agent and any predecessor thereof as against any money or property distributable to holders of claims arising out of the Prepetition Credit Agreement or any related transaction documents, including any priority in respect of payment and the right to exercise any charging lien:

- Amended and Restated Credit Agreement, dated as of June 14, 2011 (as amended by the First Amendment, dated as of May 16, 2012, the Second Amendment, dated as of November 20, 2012, the Third Amendment, dated as of November 21, 2012 and the Fourth Amendment, dated as of December 17, 2013), among Arch Coal, Inc., as borrower, the lenders from time to time party thereto, Wilmington Trust, National Association, in its capacities as term loan facility administrative agent (as successor to Bank of America, N.A. in such capacity) and collateral agent (as successor to PNC Bank, National Association in such capacity) (in such capacities, the "Prepetition Agent")

On the Effective Date, all outstanding obligations under the following credit agreement (the "DIP Credit Agreement") other than contingent and/or unliquidated obligations were paid in cash in full, all commitments under the DIP Credit Agreement and the related transaction documents referred to therein as the "Loan Documents" were terminated, all liens on property of the Debtors arising out of or related to the DIP Facility terminated and the Loan Documents were cancelled except with respect to (a) contingent and and/or unliquidated obligations under the Loan Documents which survive the Effective Date and continue to be governed by the Loan Documents and (b) the relationships among the DIP Agent (as defined below) and the lenders under the DIP Credit Agreement, as applicable, including but not limited to, those provisions relating to the rights of the

DIP Agent and the lenders to expense reimbursement, indemnification and other similar amounts, certain reinstatement obligations set forth in the DIP Credit Agreement and any provisions that may survive termination or maturity of the credit facility governed by the DIP Credit Agreement in accordance with the terms thereof:

- Superpriority Secured Debtor-In-Possession Credit Agreement, dated as of January 21, 2016 (as amended by the Waiver and Consent and Amendment No. 1, dated as of March 4, 2016, Amendment No. 2, dated as of March 28, 2016, Amendment No. 3, dated as of April 26, 2016, Amendment No. 4, dated as of June 10, 2016, Amendment No. 5, dated as of June 23, 2016, Amendment No. 6, dated as of July 20, 2016, and Amendment No. 7, dated as of September 28, 2016) among Arch Coal, Inc., as borrower, certain subsidiaries of Arch Coal, Inc., as guarantors, the lenders from time to time party there and Wilmington Trust, National Association, in its capacity as administrative agent and as collateral agent (in such capacities, the "DIP Agent").

Equity Securities

Under the Plan, 24,589,834 shares of Class A Common Stock and 410,166 shares of Class B Common Stock, par value $.01 per share, ("Class B Common Stock" and together with Class A Common Stock, "Common Stock") were distributed to the secured lenders and to certain holders of general unsecured claims under the Plan on the Effective Date. In addition, on the Effective Date, Arch Coal issued Warrants to purchase up to an aggregate of 1,914,856 shares of Class A Common Stock. Arch Coal relied, based on the confirmation order it received from the Bankruptcy Court, on Section 1145(a)(1) of the U.S. Bankruptcy Code to exempt from the registration requirements of the Securities Act of 1933, as amended (i) the offer and sale of Common Stock to the secured lenders and to the general unsecured creditors, (ii) the offer and sale of the Warrants to the holders of claims arising under the Cancelled Notes and (iii) the offer and sale of the Class A Common Stock issuable upon exercise of the Warrants. Section 1145(a)(1) of the Bankruptcy Code exempts the offer and sale of securities under a plan of
reorganization from registration under Section 5 of the Securities Act and state laws if three principal requirements are satisfied:

- the securities must be offered and sold under a plan of reorganization and must be securities of the debtor, of an affiliate participating in a joint plan of reorganization with the debtor or of a successor to the debtor under the plan of reorganization;

- the recipients of the securities must hold claims against or interests in the debtor; and

- the securities must be issued in exchange, or principally in exchange, for the recipient's claim against or interest in the debtor.

Reorganization Value

Fresh start accounting provides, among other things, for a determination of the value to be assigned to the equity of the emerging company as of a date selected for financial reporting purposes. In conjunction with the bankruptcy proceedings, a third party financial advisor provided an enterprise value of the Company of approximately $650 million to $950 million. The final equity value of $687.5 million was based upon the approximate high end of the enterprise value established by the third party valuation plus excess cash of $64 million less the fair value of debt related to the New First Lien Debt Facility of $326.5 million. The high end of the enterprise value assumed a minimum cash balance at emergence of $250 million.

The enterprise value of the Company was estimated using various valuation methods including: (i) comparable public company analysis, (ii) discounted cash flow analysis ("DCF") and (iii) sum-of-the-parts analysis. The comparable public company analysis is based on the enterprise value of selected publicly traded companies that have operating and financial characteristics comparable in certain respects to the Company, for example, operational requirements and risk and profitability characteristics. Selected companies are comprised of coal mining companies with primary operations in the United States. Under this methodology, certain financial multiples and ratios that measure financial performance and value are calculated for each selected company and then applied to the Company's financials to imply an enterprise value for the Company.

The DCF analysis is a forward-looking enterprise valuation methodology that estimates the value of an assets or business by calculating the present value of expected future cash flows by that asset or business. The basis of the DCF analysis was the Company's prepared projections which included a variety of estimates and assumptions, such as pricing and demand for coal. The Company's pricing was based on its view of the market taking into account third party forward pricing curves adjusted for the quality of products sold by the Company. While the Company considers such estimates and assumptions reasonable, they are inherently subject to significant business, economic and competitive uncertainties, many of which are beyond the Company's control and, therefore, may not be realized. Changes in these estimates and assumptions may have a significant effect on the determination of the Company's enterprise value. The assumptions used in the calculations for the DCF analysis included projected revenue, cost and cash flows for the years ending December 31, 2016 through each respective mine life and represented the Company's best estimates at the time the analysis was prepared. The DCF analysis was completed using discount rates at a range of estimated weighted average costs of capital ranging from 13.25% to 15.25% . The DCF analysis involves complex considerations and judgments concerning appropriate discount rates. Due to the unobservable inputs to the valuation, the fair value would be considered Level 3 in the fair value hierarchy.

The sum-of-the-parts analysis is a more detailed market multiples approach the values each part of a company's business separately based upon the enterprise values of selected publicly traded companies that have operating and financial characteristics comparable in certain respects to each part of the reorganized Company. Under this methodology, certain financial multiples and ratios that measure financial performance and value are calculated for each selected comparable company and then applied to the relevant segment of the Company's financials to imply an enterprise value for the Company.

Accounting Impact of Emergence

Upon emergence in accordance with ASC 852, the Company applied fresh start accounting to its consolidated financial statements as of October 1, 2016 because (i) the reorganization value of the assets of the emerging entity immediately before the date of confirmation was less than the total of all postpetition liabilities and allowed claims and (ii) the holders of the existing voting shares immediately before confirmation received less than 50 percent of the voting shares of the emerging entity. Upon adoption of fresh start accounting, the Company became a new entity for financial reporting purposes reflecting the Successor capital structure. As such, a new accounting basis in the identifiable assets and liabilities assumed was established with no retained earnings or accumulated other comprehensive income (loss) ("OCI").

The following balance sheet illustrates the impacts of the implementation of the Plan and the application of fresh start accounting, which results in the opening balance sheet of the Successor company.

As of October 1, 2016 (In thousands)	Predecessor (a)	Effect of Plan (b)		Fresh Start Adjustments (c)		Successor
Assets						
Current assets						
Cash and cash equivalents	$ 400,205	$ (199,718)	(d)	$ —		$ 200,487
Short term investments	111,451	—		—		111,451
Restricted cash	81,563	—		—		81,563
Trade accounts receivable	165,522	—		—		165,522
Other receivables	17,227	—		779	(j)	18,006
Inventories	159,410	—		(21,078)	(k)	138,332
Prepaid royalties	4,805	—		—		4,805
Deferred income taxes	—	—		—		—
Coal derivative assets	2,180	—		—		2,180
Other current assets	36,960	6,367		53,851	(l)	97,178
Total current assets	979,323	(193,351)		33,552		819,524
Property, plant and equipment, net	3,434,941	—		(2,363,829)	(m)	1,071,112
Other assets						
Prepaid royalties	20,997	—		(20,997)	(n)	—
Equity investments	164,232	—		(61,606)	(o)	102,626
Other noncurrent assets	58,569	34,495	(e)	37,503	(p)	130,567
Total other assets	243,798	34,495		(45,100)		233,193
Total assets	$ 4,658,062	$ (158,856)		$ (2,375,377)		$ 2,123,829
Liabilities and Stockholders' Equity (Deficit)						
Liabilities not subject to compromise						
Accounts payable	$ 74,595	$ —		$ (250)	(q)	$ 74,345
Accrued expenses and other current liabilities	225,739	(36,331)	(f)	26,644	(r)	216,052
Current maturities of debt	3,397	3,265	(g)	—		6,662
Total current liabilities	303,731	(33,066)		26,394		297,059
Long-term debt	30,037	323,235	(g)	—		353,272
Asset retirement obligations	394,699	—		(60,570)	(s)	334,129
Accrued pension benefits	23,716	—		24,565	(t)	48,281
Accrued other postretirement benefits	87,123	—		24,836	(t)	111,959
Accrued workers' compensation	119,828	—		74,520	(u)	194,348
Deferred income taxes	—	—		—		—
Other noncurrent liabilities	96,410	—		888	(v)	97,298
Total liabilities not subject to compromise	1,055,544	290,169		90,633		1,436,346
Liabilities subject to compromise	5,278,612	(5,278,612)	(h)	—		—
Total liabilities	6,334,156	(4,988,443)		90,633		1,436,346
Stockholders' equity (deficit)						
Common stock, predecessor	2,145	(2,145)	(i)	—		—
Common stock, successor	—	250	(b)	—		250
Paid-in capital, predecessor	3,056,307	(3,056,307)	(i)	—		—
Paid-in capital, successor	—	687,233	(b)	—		687,233
Treasury stock, at cost	(53,863)	53,863	(i)	—		—
Accumulated earnings (deficit)	(4,678,977)	7,146,693	(i)	(2,467,716)		—
Accumulated other comprehensive income (loss)	(1,706)	—		1,706		—
Total stockholders' equity (deficit)	(1,676,094)	4,829,587		(2,466,010)		687,483
Total liabilities and stockholders' equity (deficit)	$ 4,658,062	$ (158,856)		$ (2,375,377)		$ 2,123,829

(a) Represents the Predecessor consolidated balance sheet as of October 1, 2016.

(b) Represents amounts recorded for the implementation of the Plan on the Effective Date. This includes the settlement of liabilities subject to compromise through a combination of cash payments, the issuance of new common stock and warrants and the issuance of new debt. The following is the calculation of the total pre-tax gain on the settlement of the liabilities subject to compromise:

	In thousands
Liabilities subject to compromise	$ 5,278,612
Less amounts issued to settle claims:	
Common stock (at par) Successor	(250)
Warrants Successor	(14,822)
Paid-in capital Successor	(672,411)
Issuance of Term Loan Successor	(326,500)
Cash payment to settle claims and professional fees	(122,525)
Total pre-tax gain on plan effects	$ 4,142,104

(c) Represents the fresh start accounting adjustments required to record the assets and liabilities of the Company at fair value.

(d) The following table reflects the use of cash at emergence:

	In thousands
Payment to secured lenders	$ 43,496
Payments to unsecured creditors	42,399
Final adequate protection payment	36,331
Collateral requirements	31,665
Professional fees	31,630
Other	14,197
Total cash outflow at emergence	$ 199,718

(e) Represents amounts paid for required collateral deposits.

(f) Represents the final adequate protection payments made to the secured lenders.

(g) Represents the fair value of the $326.5 million new term loan of which $3.3 million is shown within current maturities of debt.

(h) Liabilities subject to compromise include unsecured or under-secured liabilities incurred prior to the Chapter 11 filing; and consists of the following:

Previously Reported Balance Sheet Line	In thousands
Debt	$ 5,026,806
Accrued expenses and other current liabilities	136,295
Accounts payable	106,297
Other noncurrent liabilities	9,214
Total liabilities subject to compromise	$ 5,278,612

(i) Reflects the impacts of the reorganization adjustments:

	In thousands
Total pre-tax gain on settlement of claims	$ 4,142,104
Cancellation of predecessor common stock	2,145
Cancellation of predecessor paid-in capital	3,056,307
Cancellation of predecessor treasury stock	(53,863)
Net impact on accumulated earnings (deficit)	$ 7,146,693

(j) Represents adjustments to record other receivables at fair value which includes an $0.8 million short-term receivable related to insurance coverage for self-insured workers' compensation obligations.

(k) Represents the following fair value adjustments: a $7.3 million increase related to coal inventory which was fair valued at estimated selling prices less the sum of selling costs, shipping costs and a reasonable profit allowance for the selling effort offset by a $28.4 million reduction in critical spare parts inventory. During fresh start accounting, the Company changed its accounting policy with respect to critical spare parts with long lead times; previously these items were valued within inventory, but prospectively, these items will be capitalized within property, plant and equipment when purchased and depreciated over the life of the related equipment.

(l) Represents the short-term portion of above market coal sales contracts of $71.1 million offset by $11.3 million in reductions related to prepaid balances. The fair value of sales contracts was estimated using a discounted cash flow model and will be amortized into earnings as the coal is shipped throughout the term of the associated contracts.

(m) Represents a $2.4 billion reduction in property, plant and equipment to estimated fair value as discussed below:

(in thousands)	Predecessor	Fresh Start Adjustments	Successor
Net Coal Properties	$ 2,358,779	$ (1,971,314)	$ 387,465
Net Plant & Equipment	812,888	(405,259)	407,629
Net Deferred Charges	263,274	12,744	276,018
	$ 3,434,941	$ (2,363,829)	$ 1,071,112

The fair value of coal properties was established at $387.5 million utilizing a discounted cash flow model and the market approach. The market approach was used to provide a starting value of the coal mineral reserves without consideration for economic obsolescence. The DCF model was based on assumptions market participants would use in the pricing of these assets as well as projections of revenues and expenditures that would be incurred to mine or maintain these coal reserves through the life of mine. The basis of the DCF analysis was the Company's prepared projections which included a variety of estimates and assumptions, such as pricing and demand for coal. The Company's pricing was based on its view of the market taking into account third party forward pricing curves adjusted for the quality of products sold by the Company.

The fair value of plant and equipment was set at $407.6 million utilizing both market and cost approaches. The market approach was used to estimate the value of assets where detailed information for the asset was available and an active market was identified with a sufficient number of sales of comparable property that could be independently verified through reliable sources. The cost approach was utilized where there were limitations in the secondary equipment market to derive values from. The first step in the cost approach is the estimation of the cost required to replace the asset via construction or purchasing a new asset with similar utility adjusting for depreciation due to physical deterioration, functional obsolescence due to technology changes and economic obsolescence due to external factors such as regulatory changes. Useful lives were assigned to all assets based on remaining future economic benefit of each asset.

The fair value of deferred charges represents the corresponding asset related to the asset retirement obligation discussed in item (q) below.

(n) Represents a fair value adjustment to a long-term prepaid royalty balance that the Company has concluded should not be assigned value based on market conditions and after considering economic obsolescence.

(o) Represents a fair value adjustment to the Company’s equity investments in Knight Hawk Holdings, LLC, a coal producer in the Illinois Basin; and Dominion Terminal Associates which operates a ground storage-to-vessel coal trans-loading facility in Newport News, Virginia. Equity investments were fair valued in a manner similar to the Company’s wholly-owned subsidiaries using a discounted cash flow model and comparable company approach. The discount rate selected was 14% and due to the unobservable nature of the inputs, the fair values are considered Level 3 in the fair value hierarchy.

(p) Represents the long-term portion of above market coal sales contracts of $26.0 million and $18.6 million related to a long-term insurance receivable related to insurance coverage for self-insured workers’ compensation obligations partially offset by $13.2 million in reductions related to prepaid balances. The fair value of sales contracts was estimated using a discounted cash flow model and will be amortized into earnings as the coal is shipped throughout the term of the associated contracts.

(q) Represents a fair value adjustment to miscellaneous accounts payable.

(r) Represents fair value adjustments for the following: a $27.8 million increase related to the short-term portion of below market sales contracts offset by fair value adjustments to establish the current portion of pension, postretirement and workers’ compensation liabilities. The fair value of sales contracts was estimated using a discounted cash flow model and will be amortized into earnings as the coal is shipped throughout the term of the associated contracts.

(s) Represents the fair value adjustment related to the Company’s asset retirement obligations which was calculated using discounted cash flow models based on current mine plans using the guidance provided within Accounting Standard Codification 410-20, “Asset Retirement Obligations.” The discount rates ranged from 7.06% to 9.08%.

(t) Pension and postretirement benefits were fair valued based on plan assets and employee benefit obligations at October 1, 2016. The benefit obligations were computed using the applicable October 1, 2016 discount rates. In conjunction with fresh start accounting, the Company updated its mortality rate table assumptions and corridor assumption.

(u) Represents fair value adjustments for workers’ compensation benefits, including occupational disease benefits, that were actuarially determined using the guidance provided within Accounting Standard Codification 712, “Non-retirement Post-employment Benefits.” Upon emergence, the Company’s accounting policy is to actuarially calculate this liability. Prior to emergence, the Company had accounted for its liability based on outstanding reserves calculated per third party administrators.

(v) Represents the following fair value adjustments: $3.9 million increase related to the long-term portion of below market sales contracts partially offset by $3.1 million reduction in miscellaneous noncurrent liabilities. The fair value of sales contracts was estimated using a discounted cash flow model and will be amortized into earnings as the coal is shipped throughout the term of the associated contracts.

Reorganization Items, Net

In accordance with ASC 852, the statement of operations shall portray the results of operations of the reporting entity while it is in Chapter 11. Revenues, expenses (including professional fees), realized gains and losses, and provisions for losses resulting from reorganization and restructuring of the business shall be reported separately as reorganization items.

The Company's reorganization items, net for the respective periods are as follows:

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(In thousands)				
Gain on settlement of claims (per above)	$ —	$ 4,142,104	$ —	$ —
Fresh start adjustments, net (per above)	—	(2,466,010)	—	—
Professional fees	(759)	(46,053)	—	—
	$ (759)	$ 1,630,041	$ —	$ —

Professional fees directly related to the reorganization include fees associated with advisors to the Company, certain secured creditors and the Creditors' Committee. During the Successor period ended December 31, 2016, the Company continued to incur costs related to professional fees that are directly attributable to the reorganization.

Contractual Interest Expense During Bankruptcy

Upon the filing of bankruptcy, the Company discontinued recording interest expense on unsecured debt that was classified as a liability subject to compromise. Actual interest expense recorded on the Predecessor debt subsequent to the Petition Date was $135.9 million for the period January 1 through October 1, 2016; contractual interest during this time was $300.9 million.

4. Accumulated Other Comprehensive Income (Loss)

The following items are included in accumulated other comprehensive income (loss):

	Derivative Instruments	Pension, Postretirement and Other Post-Employment Benefits	Available-for-Sale Securities	Accumulated Other Comprehensive Income (Loss)
	(In thousands)			
Predecessor Company				
January 1, 2015	$ 2,550	$ 2,860	$ (2,169)	$ 3,241
Unrealized gains (losses)	3,903	(8,723)	(3,333)	(8,153)
Amounts reclassified from accumulated other comprehensive income (loss)	(6,128)	5,142	4,083	3,097
December 31, 2015	325	(721)	(1,419)	(1,815)
Unrealized gains (losses)	(138)	—	701	563
Amounts reclassified from accumulated other comprehensive income (loss)	(316)	(1,363)	1,225	(454)
Fresh start accounting adjustment	129	2,084	(507)	1,706
October 1, 2016	$ —	$ —	$ —	$ —
Successor Company				
Unrealized gains	—	24,067	387	24,454
Amounts reclassified from accumulated other comprehensive income (loss)	—	—	—	—
December 31, 2016	$ —	$ 24,067	$ 387	$ 24,454

The unrealized gain in the successor period is the result of changes in the discount rates used to calculate our pension, postretirement health and occupational disease obligations.

The following amounts were reclassified out of accumulated other comprehensive income (loss) during the respective periods:

Details about accumulated other comprehensive income components	Successor	Predecessor		Line Item in the Consolidated Statement of Operations
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	
	(in thousands)	(in thousands)		
Derivative instruments	$ —	$ 397	$ 9,575	Revenues
	—	(81)	(3,447)	Provision for (benefit from) income taxes
	$ —	$ 316	$ 6,128	Net of tax
Pension, postretirement and other post-employment benefits				
Amortization of prior service credits [1]	$ —	$ 7,854	$ 8,335	
Amortization of net actuarial gains (losses) [1]	—	(6,010)	(16,369)	
	—	1,844	(8,034)	Total before tax
	—	(481)	2,892	Provision for (benefit from) income taxes
	$ —	$ 1,363	$ (5,142)	Net of tax
Available-for-sale securities [2]	$ —	$ (2,263)	$ (6,391)	Interest and investment income
	—	1,038	2,308	Provision for (benefit from) income taxes
	$ —	$ (1,225)	$ (4,083)	Net of tax

[1] Production-related benefits and workers' compensation costs are included in costs to produce coal.

[2] The gains and losses on sales of available-for-sale-securities are determined on a specific identification basis.

5. Impairment Charges and Mine Closure Costs

The following table summarizes the amounts reflected on the line "Asset impairment and mine closure costs" in the consolidated statements of operations:

	Successor	Predecessor		
Description	October 2 Through December 31, 2016	January 1 Through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
			(In thousands)	
Coal lands and mineral rights	$ —	$ 74,144	$ 2,210,488	$ —
Plant and equipment	—	—	199,107	1,512
Deferred development	—	—	159,474	—
Prepaid royalties	—	3,406	41,990	15,356
Equity investments	—	40,920	21,325	—
Inventories	—	—	66	—
Other	—	10,797	(4,147)	7,245
Total	$ —	$ 129,267	$ 2,628,303	$ 24,113

January 1 Through October 1, 2016 Impairment Charges

During the period January 1 through October 1, 2016, the Company recorded the following to "Asset impairment and mine closure costs" in the Consolidated Statements of Operations: $74.1 million recorded in the first quarter related to the impairment of coal reserves and surface land in Kentucky that are being leased to a mining company that idled its mining operations; $3.4 million recorded in the first quarter related to the impairment on the portion of an advance royalty balance on a reserve base mined at the Company's Mountain Laurel operation that will not be recouped; $2.9 million recorded in the first quarter related to an other-than-temporary-impairment charge on an available-for-sale security; a $38.0 million impairment recorded in the second quarter related to the Company's equity investment in a brownfield bulk commodity terminal on the Columbia River in Longview, Washington as the Company relinquished its ownership rights in exchange for future throughput rights; $7.2 million of severance expense related to headcount reductions during the first half of the year; a $3.6 million curtailment charge related to the Company's pension, postretirement health and black lung actuarial liabilities due to headcount reductions in the first half of the year.

2015 Impairment Charges

In 2015, as a result of the continued deterioration in thermal and metallurgical coal markets and projections for a muted pricing recovery, certain of the Company's mine complexes have incurred and are expected to continue to incur operating losses. The Company determined that the further weakening of the pricing environment in the last half of the year and the projected operating losses represented indicators of impairment with respect to certain of its long-lived assets or assets groups. Using current pricing expectations which reflected marketplace participant assumptions, life of mine cash flows were used to determine if the undiscounted cash flows exceeded the current asset values for certain operating complexes in the Company's Appalachia segment. For multiple operating complexes, the undiscounted cash flows did not exceed the carrying value of the long-lived assets. Discounted cash flows were utilized to reduce the carrying value of those assets to fair value. The discount rate used reflected the then current financial difficulties present in the commodities sector in general and coal mining specifically; the perceived risk of financing coal mining in light of industry defaults; and the lack of an active market for buying or selling coal mining assets. Additionally, the Company determined that the then current market conditions represented an indicator of impairment for certain undeveloped coal properties that were acquired in times of significantly higher coal prices. The then current prices and the significant capital outlay that would have been required to develop these reserves indicated that the carrying value was not recoverable. As a result the Company recorded a $2.6 billion asset impairment charge in the last two quarters of 2015 of which $2.1 billion was recorded during the third quarter and the remaining $0.5 billion was recorded in the fourth quarter. Of the total charge. $2.2 billion was recorded to the Company's Appalachia segment, with the remaining $0.4 billion recorded to the Company's Other operating segment. There is no fair value remaining related to the impaired assets.

During the second quarter of 2015, the Company recorded $19.1 million to "Asset impairment and mine closure costs" in the Consolidated Statements of Operations. An impairment charge of $12.2 million related to the portion of an advance royalty balance on a reserve base mined at the Company's Mountain Laurel, Spruce and Briar Branch operations that was determined would not be recouped based on estimates of sales volume and pricing through the March 2017 recoupment period. Additionally, the Company recorded a $5.6 million impairment charge related to the closure of a higher-cost mining complex serving the metallurgical coal markets.

2014 Impairment Charges

During the Company's annual budgeting process for 2015 (performed in the fall of 2014), a review of forecasted revenues indicated that the remaining balance of advance royalty payments made on a reserve base supplying the Company's Mountain Laurel, Spruce Mine and Briar Branch operations would not be recoupable against future royalties payments. Under the lease, any unrecouped advance payment balance at March 31, 2017 will be forfeited by the Company. Based on estimates of sales volumes and pricing through the end of the recoupment period, an impairment charge was recorded during the fourth quarter of 2014 for $15.4 million of the remaining $48.0 million balance that was determined would not be recouped.

In response to weak metallurgical coal markets the Company idled a higher-cost mining complex in the third quarter of 2014 in order to concentrate on metallurgical coal production from its lowest-cost and highest-margin operations. Closure charges of $5.1 million were recognized during the third quarter of 2014 relating to the idling.

6. Losses from disposed operations resulting from Patriot Coal bankruptcy

On December 31, 2005, Arch entered into a purchase and sale agreement with Magnum to sell certain operations. On July 23, 2008, Patriot acquired Magnum. On May 12, 2015, Patriot and certain of its wholly owned subsidiaries ("Debtors"), including Magnum, filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Eastern District of Virginia. Subsequently, on October 28, 2015, Patriot's Plan of Reorganization was approved, including an authorization to reject their collective bargaining agreements and modify certain union-related retiree benefits. As a result of the Plan of Reorganization, the Company became statutorily responsible for retiree medical benefits pursuant to Section 9711 of the Coal Industry Retiree Health Benefit Act of 1992 for certain retirees of Magnum who retired prior to October 1, 1994. In addition, the Company has provided surety bonds to Patriot related to permits that were sold to an affiliate of Virginia Conservation Legacy Fund, Inc. ("VCLF"). Should VCLF not perform required reclamation, the Company would incur losses under the bonds and related indemnity agreements. The Company recognized $116.3 million in losses in 2015 related to the previously disposed operations as a result of the Patriot Coal bankruptcy.

On November 22, 2016, Arch entered into a"Collateral Use Agreement" which caused the replacement, substitution and discharge of reclamation surety bonds related to the former Magnum properties placed by Arch in exchange for a collateral release of $20 million held by the bonding company to VCLF.

7. **Inventories**

Inventories consist of the following:

	Successor	Predecessor
	December 31, 2016	**December 31, 2015**
(In thousands)		
Coal	$ 37,268	$ 85,043
Repair parts and supplies	76,194	111,677
	$ 113,462	$ 196,720

The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $0.0 million at December 31, 2016 and $6.0 million at December 31, 2015.

8. **Investments in Available-for-Sale Securities**

The Company has invested primarily in highly liquid investment-grade corporate bonds. These investments are held in the custody of a major financial institution. These securities, along with the Company's investments in marketable equity securities, are classified as available-for-sale securities and, accordingly, the unrealized gains and losses are recorded through other comprehensive income.

The Company's investments in available-for-sale marketable securities are as follows:

	Successor					
	December 31, 2016					
					Balance Sheet Classification	
	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Short-Term Investments	Other Assets
	(In thousands)					
Available-for-sale:						
Corporate notes and bonds	$ 88,161	$ —	$ (89)	$ 88,072	$ 88,072	$ —
Equity securities	1,749	388	—	2,137	—	2,137
Total Investments	$ 89,910	$ 388	$ (89)	$ 90,209	$ 88,072	$ 2,137

	Predecessor					
	December 31, 2015					
					Balance Sheet Classification	
	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Short-Term Investments	Other Assets
	(In thousands)					
Available-for-sale:						
U.S. government and agency securities	$ 10,007	$ —	$ (12)	$ 9,995	$ 9,995	$ —
Corporate notes and bonds	190,496	—	(299)	190,197	190,197	—
Equity securities	3,938	668	(2,888)	1,718	—	1,718
Total Investments	$ 204,441	$ 668	$ (3,199)	$ 201,910	$ 200,192	$ 1,718

The aggregate fair value of investments with unrealized losses that had been owned for less than a year was $47.6 million and $184.6 million at December 31, 2016 and 2015, respectively. The aggregate fair value of investments with unrealized losses that have been owned for over a year was $40.4 million and $15.8 million at December 31, 2016 and 2015, respectively.

The debt securities outstanding at December 31, 2016 have maturity dates ranging from the first quarter of 2017 through the fourth quarter of 2017. The Company classifies its investments as current based on the nature of the investments and their availability to provide cash for use in current operations, if needed.

9. **Equity Method Investments and Membership Interests in Joint Ventures**

The Company accounts for its investments and membership interests in joint ventures under the equity method of accounting if the Company has the ability to exercise significant influence, but not control, over the entity. Equity method investments are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable.

Below are the equity method investments reflected in the consolidated balance sheets:

(In thousands)	Knight Hawk	DTA	Millennium	Tongue River	Other	Total
Predecessor Company						
January 1, 2014	$ 152,806	$ 14,137	$ 35,894	$ 18,419	$ 200	$ 221,456
Advances to (distributions from) affiliates, net	(12,603)	3,774	6,742	2,541	3,600	4,054
Equity in comprehensive income (loss)	18,274	(4,173)	(2,413)	(220)	(1,136)	10,332
December 31, 2014	158,477	13,738	40,223	20,740	2,664	235,842
Advances to (distributions from) affiliates, net	(29,862)	3,207	7,052	913	330	(18,360)
Equity in comprehensive income (loss)	22,977	(3,706)	(9,686)	(328)	(1,278)	7,979
Impairment of equity investment	—	—	—	(21,325)		(21,325)
Sale of equity investment	—	—	—	—	(2,259)	(2,259)
December 31, 2015	151,592	13,239	37,589	—	(543)	201,877
Advances to (distributions from) affiliates, net	(8,374)	1,474	1,966	—	—	(4,934)
Equity in comprehensive income (loss)	9,033	(2,095)	(1,530)	—	(94)	5,314
Impairment of equity investment	—	—	(38,025)	—	—	(38,025)
Fresh start accounting adjustment	(58,251)	(4,018)	—	—	662	(61,607)
October 1, 2016	$ 94,000	$ 8,600	$ —	$ —	$ 25	$ 102,625
Successor Company						
Advances to (distributions from) affiliates, net	(9,076)	822	—	—	—	(8,254)
Equity in comprehensive income (loss)	2,569	(841)	—	—	(25)	1,703
December 31, 2016	$ 87,493	$ 8,581	$ —	$ —	$ —	$ 96,074

The Company holds a 49% equity interest in Knight Hawk Holdings, LLC ("Knight Hawk"), a coal producer in the Illinois Basin.

The Company holds a general partnership interest of 21.875% in Dominion Terminal Associates ("DTA"), which is accounted for under the equity method. DTA operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia for use by the partners. Under the terms of a throughput and handling agreement with DTA, each partner is charged its share of cash operating and debt-service costs in exchange for the right to use the facility's loading capacity and is required to make periodic cash advances to DTA to fund such costs.

The Company previously held a 38% ownership interest in Millennium Bulk Terminals-Longview, LLC ("Millennium"), the owner of a brownfield bulk commodity terminal on the Columbia River near Longview, Washington. Millennium continues to work on obtaining the required approvals and necessary permits to complete dredging and other upgrades to ship coal, alumina and cementitious material from the terminal. During the second quarter of 2016, the Company recorded an impairment charge of $38.0 million representing the entire value of its equity investment as the Company relinquished its ownership rights in exchange for future throughput rights through the facility when completed.

The Company holds a 35% membership interest in the Tongue River Holding Company, LLC ("Tongue River") joint venture. Tongue River will develop and construct a railway line near Miles City, Montana and the Company's Otter Creek reserves. The Company had the right, upon the receipt of permits and approval for construction or under other prescribed circumstances, to require the other investors to purchase all of the Company's units in the venture at an amount equal to the capital contributions made by the Company at that time, less any distributions received. During the third quarter of 2015, the Company recorded an impairment charge of $21.3 million representing the entire value of the Company's investment in the project; the impairment charge is included on the line "Asset impairment and mine closure costs."

The Company is not required to make any future contingent payments related to development financing for any of its equity investees.

10. Sales Contracts

The sales contracts reflected in the consolidated balance sheets are as follows:

	Successor			Predecessor		
	December 31, 2016			December 31, 2015		
	Assets	Liabilities	Net Total	Assets	Liabilities	Net Total
	(In thousands)			(In thousands)		
Original fair value	$ 97,196	$ 31,742		$ 131,299	$ 166,697	
Accumulated amortization	(25,625)	(24,829)		(130,839)	(151,354)	
Total	$ 71,571	$ 6,913	$ 64,658	$ 460	$ 15,343	$ (14,883)
Balance Sheet classification:						
Other current	$ 59,702	$ 5,114		$ 460	$ 3,852	
Other noncurrent	$ 11,869	$ 1,799		$ —	$ 11,491	

The Company anticipates amortization of sales contracts, based upon expected shipments in the next five years, to be expense of approximately $54.3 million in 2017, $10.7 million in 2018, $1.1 million in 2019, and income of $0.6 million in 2020 and $0.1 million in 2021.

11. **Derivatives**

Diesel fuel price risk management

The Company is exposed to price risk with respect to diesel fuel purchased for use in its operations. The Company anticipates purchasing approximately 45 to 50 million gallons of diesel fuel for use in its operations during 2017. To protect the Company's cash flows from increases in the price of diesel fuel for its operations, the Company may use forward physical diesel purchase contracts and purchase out-of-the-money heating oil call options to protect against substantial increases in pricing. At December 31, 2016, the Company had heating oil call options for approximately 30.7 million gallons at an average strike price of $1.72.

Coal risk management positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market in order to manage its exposure to coal prices. The Company has exposure to the risk of fluctuating coal prices related to forecasted sales or purchases of coal or to the risk of changes in the fair value of a fixed price physical sales contract. Certain derivative contracts may be designated as hedges of these risks.

At December 31, 2016, the Company held derivatives for risk management purposes that are expected to settle in the following years:

(Tons in thousands)	2017	2018	Total
Coal sales	540	—	540
Coal purchases	480	—	480

Coal trading positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market for trading purposes. The Company is exposed to the risk of changes in coal prices on the value of its coal trading portfolio. The unrecognized gains of $0.2 million in the trading portfolio are expected to be realized in 2017.

Tabular derivatives disclosures

The Company has master netting agreements with all of its counterparties which allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. Such netting arrangements reduce the Company's credit exposure related to these counterparties. For classification purposes, the Company records the net fair value of all the positions with a given counterparty as a net asset or liability in the consolidated balance sheets. The amounts shown in the table below represent the fair value position of individual contracts, and not the net position presented in the accompanying consolidated balance sheets.

The fair value and location of derivatives reflected in the accompanying consolidated balance sheets are as follows:

	Successor			Predecessor		
	December 31, 2016			December 31, 2015		
Fair Value of Derivatives (In thousands)	**Asset Derivative**	**Liability Derivative**		**Asset Derivative**	**Liability Derivative**	
Derivatives Designated as Hedging Instruments						
Coal	$ —	$ (15)		$ 4	$ (20)	
Derivatives Not Designated as Hedging Instruments						
Heating oil -- diesel purchases	4,646	—		1,017	—	
Coal held for trading purposes, exchange traded swaps and futures	68,948	(68,740)		110,653	(104,814)	
Coal -- risk management	475	(580)		3,912	(1,947)	
Natural gas	86	(13)		494	(247)	
Total	74,155	(69,333)		116,076	(107,008)	
Total derivatives	74,155	(69,348)		116,080	(107,028)	
Effect of counterparty netting	(69,247)	69,247		(107,028)	107,028	
Net derivatives as classified in the balance sheets	$ 4,908	$ (101)	$ 4,807	$ 9,052	$ —	$ 9,052

		Successor	Predecessor
		December 31, 2016	December 31, 2015
Net derivatives as reflected on the balance sheets			
Heating oil	Other current assets	$ 4,646	$ 1,017
Coal	Coal derivative assets	262	8,035
	Accrued expenses and other current liabilities	(101)	—
		$ 4,807	$ 9,052

The Company had a current asset for the right to reclaim cash collateral of $2.8 million and $1.7 million at December 31, 2016 and 2015, respectively. These amounts are not included with the derivatives presented in the table above and are included in "other current assets" in the accompanying consolidated balance sheets.

The effects of derivatives on measures of financial performance are as follows:

Derivatives used in Cash Flow Hedging Relationships (in thousands)
For the noted periods,

		Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion)			
		Successor	Predecessor		
		October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Coal sales	(1)	$ —	$ (672)	$ 12,816	10,842
Coal purchases	(2)	—	536	(6,718)	(5,097)
		$ —	$ (136)	$ 6,098	$ 5,745

	Gains (Losses) Reclassified from Other Comprehensive Income into Income (Effective Portion)			
	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Coal sales	$ —	$ 1,634	$ 18,635	$ 5,336
Coal purchases	—	(1,237)	(9,060)	(2,693)
	$ —	$ 397	$ 9,575	$ 2,643

No ineffectiveness or amounts excluded from effectiveness testing relating to the Company's cash flow hedging relationships were recognized in the results of operations in the Successor period from October 2 through December 31, 2016, the Predecessor period from January 1 through October 1, 2016, and for the Predecessor years ended December 31, 2015, and 2014.

Derivatives Not Designated as Hedging Instruments (in thousands)
For the noted periods,

		Gain (Loss) Recognized			
		Successor	Predecessor		
		October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Coal — unrealized	(3)	$ (408)	$ (1,662)	$ (3,883)	$ 430
Coal — realized	(4)	$ 116	$ (476)	$ 3,236	$ 5,956
Heating oil — diesel purchases	(4)	$ 827	$ 826	$ (8,294)	$ (7,848)
Heating oil — fuel surcharges	(4)	$ —	$ —	$ —	$ (405)
Natural gas		$ (91)	$ (463)	$ 878	$ —
Foreign currency		$ (9)	$ (451)	$ (887)	$ —

Location in statement of operations:
(1) — Revenues
(2) — Cost of sales
(3) — Change in fair value of coal derivatives and coal trading activities, net
(4) — Other operating income, net
The Company recognized net unrealized and realized losses of an immaterial amount for the period October 2 through December 31, 2016 and $0.9 million for the period January 1 through October 1, 2016; and net unrealized and realized gains of $5.7 million, and $3.2 million during the years ended December 31, 2015 and 2014, respectively, related to its trading portfolio, which are included in the caption "Change in fair value of coal derivatives and coal trading activities, net" in the accompanying consolidated statements of operations, and are not included in the previous tables reflecting the effects of derivatives on measures of financial performance.

Based on fair values at December 31, 2016, amounts on derivative contracts designated as hedge instruments in cash flow hedges expected to be reclassified from other comprehensive income into earnings during the next twelve months are immaterial.

12. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following:

	Successor	Predecessor
	December 31, 2016	December 31, 2015
(In thousands)		
Payroll and employee benefits	$ 58,468	$ 58,423
Taxes other than income taxes	92,733	104,755
Interest	8,032	119,785
Sales contracts	5,114	3,852
Workers' compensation	15,184	16,875
Asset retirement obligations	19,515	13,795
Other	6,194	11,965
	$ 205,240	$ 329,450

13. Debt and Financing Arrangements

	Successor	Predecessor
	December 31, 2016	December 31, 2015
(In thousands)		
Term loan due 2021 ($325.7 million face value)	$ 325,684	$ —
Term loan due 2018 ($1.9 billion and $1.93 billion face value, respectively)	—	1,875,429
7.00% senior notes due 2019 at par	—	1,000,000
8.00% senior secured notes due 2019 at par	—	350,000
9.875% senior notes ($375.0 million face value) due 2019	—	365,600
7.25% senior notes due 2020 at par	—	500,000
7.25% senior notes due 2021 at par	—	1,000,000
Other	37,195	47,134
Debt issuance costs	—	(64,857)
	362,879	5,073,306
Less current maturities of debt	11,038	5,042,353
Long-term debt	$ 351,841	$ 30,953

Successor Company Debt

New First Lien Debt Facility

Borrowings under the New First Lien Debt Facility bear interest at a per annum rate equal to, at the option of Arch Coal, either (i) a London interbank offered rate plus an applicable margin of 9%, subject to a 1% LIBOR floor (the "LIBOR Rate"), or (ii) a base rate plus an applicable margin of 8%. Interest payments will be payable in cash, unless Arch Coal's liquidity (as defined therein) after giving effect to the applicable interest payment would not exceed $300 million, in which case interest may be payable in kind (any such interest that is paid in kind, the "PIK Interest"). The term loans provided under the New First Lien Debt Facility (the "Term Loans") are subject to quarterly principal amortization payments in an amount equal $816,250. To the extent any interest is paid as PIK Interest on any interest payment date, the amount of the Term Loans in respect of which such PIK Interest is payable will be deemed to have accrued additional interest over the preceding interest period at 1.00%, which additional interest will be capitalized and added to the principal amount of outstanding Term Loans. The New First Lien Debt Facility is guaranteed by all existing and future wholly owned domestic subsidiaries of Arch Coal (collectively, the "Subsidiary Guarantors" and, together with Arch Coal, the "Exit Loan Parties"), subject to customary exceptions, and is secured by first priority security interests on substantially all assets of the Exit Loan Parties, including 100% of the voting equity interests of directly owned domestic subsidiaries and 65% of the voting equity interests of directly owned foreign subsidiaries, subject to customary exceptions. Arch Coal has the right to prepay Term Loans at any time and from time to time in whole or in part without premium or penalty, upon written notice, except that any prepayment of Term Loans that bear interest at the LIBOR Rate other than at the end of the applicable interest periods therefor shall be made with reimbursement for any funding losses and redeployment costs of the Lenders resulting therefrom. The New First Lien Debt Facility is subject to certain usual and customary mandatory prepayment events, including 100% of net cash proceeds of (i) debt issuances (other than debt permitted to be incurred under the terms of the New First Lien Debt Facility) and (ii) non-ordinary course asset sales or dispositions, subject to customary thresholds, exceptions and reinvestment rights. The New First Lien Debt Facility contains customary affirmative covenants and representations. The New First Lien Debt Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) indebtedness, (ii) liens and guaranties, (iii) liquidations, mergers, consolidations, 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 indebtedness, (x) restrictions in agreements on dividends, intercompany loans and granting liens on the collateral, (xi) loans and investments, (xii) changes in organizational documents, (xiii) transactions with respect to bonding subsidiaries and (xiv) hedging transactions. The New First Lien Debt Facility does not contain any financial maintenance covenant. The New First Lien Debt Facility contains customary events of default, subject to customary thresholds and exceptions, including, among other things, (i) non-payment of principal and non-payment of interest and fees, (ii) a material inaccuracy of a representation or warranty at the time made, (iii) a failure to comply with any covenant, subject to customary grace periods in the case of certain affirmative covenants, (iv) cross-events of default to indebtedness of at least $35 million, (v) cross-events of default to surety, reclamation or similar bonds securing obligations with an aggregate face amount of at least $50 million, (vi) uninsured judgments in excess of $35 million, (vii) any loan document shall cease to be a legal, valid and binding agreement, (viii) uninsured losses or proceedings against assets with a value in excess of $35 million, (ix) ERISA events, (x) a change of control or (xi) bankruptcy or insolvency proceedings relating to Arch Coal or any material subsidiary of Arch Coal. The New First Lien Debt Facility will mature on the date that is five years after the Effective Date.

Securitization Facility

On the Effective Date, Arch Coal extended and amended its existing $200 million trade accounts receivable securitization facility provided to Arch Receivable Company, LLC, a non-Debtor special-purpose entity that is a wholly owned subsidiary of Arch Coal ("Arch Receivable") (the "Extended Securitization Facility"), which continues to support the issuance of letters of credit and reinstates Arch Receivable's ability to request cash advances, as existed prior to the filing of the voluntary petitions for relief under the Bankruptcy Code. Pursuant to the Extended Securitization Facility, the Debtors agreed to a revised schedule of fees payable to the administrator and the providers of the Extended Securitization Facility. The Extended Securitization Facility will terminate at the earliest of (i) three years from the Effective Date, (ii) if the Liquidity (defined in the Extended Securitization Facility and consistent with the definition in the New First Lien Debt Facility) is less than $175 million for a period of 60 consecutive days, the date that is the 364th day after the first day of such 60 consecutive day period and (iii) the occurrence of certain predefined events substantially consistent with the existing transaction documents. Under the Extended Securitization Facility, Arch Receivable and certain of the Reorganized Debtors (as defined above) party to the Extended Securitization Facility have granted to the administrator of the Extended Securitization Facility a first priority security interest in eligible trade accounts receivable generated by such Debtors from the sale of coal and all proceeds thereof. As of December 31, 2016, letters of credit totaling $154.4 million were outstanding under the Extended Securitization Facility and the borrowing base was $83.4 million. As a result, cash collateral of $71.0 million has been placed in the Extended Securitization Facility at December 31, 2016 and there is no availability for borrowings.

Predecessor Company Debt

The following debt instruments were fully discharged by the Bankruptcy Court:

- 7.00% Senior Notes due 2019;
- 7.25% Senior Notes due 2020;
- 7.25% Senior Notes due 2021;
- 9.875% Senior Notes due 2019;
- 8.00% Second Lien Notes due 2019;
- Term loan due 2018;

For additional information see Note 3, "Emergence from Bankruptcy and Fresh Start Accounting."

Debt Maturities

The contractual maturities of debt as of December 31, 2016 are as follows:

Year		(In thousands)
2017	$	11,038
2018		10,324
2019		11,479
2020		11,761
2021		317,987
Thereafter		290
	$	362,879

Financing Costs

The Company paid financing costs of $23.0 million during the period January 1 through October 1, 2016; and zero and $4.5 million during the years ended December 31, 2015 and 2014, respectively, in conjunction with its financing activities.

The Company incurred $2.2 million of legal fees and financial advisory fees associated with debt restructuring activities in during the period January 1 through October 1, 2016. Additionally, the Company incurred $24.2 million of legal fees and financial advisory fees associated with debt restructuring activities during 2015. During the year ended December 31, 2015, the Company wrote off $3.7 million of deferred financing costs related to the termination of the revolver facility. All amounts have been reflected in the line, "Net loss resulting from early retirement and refinancing of debt" in the Consolidated Statement of Operations.

14. Taxes

Under the Plan, the Company's pre-petition equity, bank related debt and certain other obligations were cancelled and extinguished. Absent an exception, a debtor recognizes cancellation of debt income (CODI) upon discharge of its outstanding indebtedness for an amount of consideration that is less than its adjusted issue price. In accordance with Internal Revenue Code (IRC) Section 108, the Company excluded the amount of discharged indebtedness from taxable income since the IRC provides that a debtor in a bankruptcy case may exclude CODI from income but must reduce certain tax attributes by the amount of CODI realized as a result of the consummation of a plan of reorganization. The amount of CODI realized by a taxpayer is the adjusted issue price of any indebtedness discharged less than the sum of (i) the amount of cash paid, (ii) the issue price of any new indebtedness issued, and (iii) the fair market value the fair market value of any other consideration, including equity, issued.

CODI from the discharge of indebtedness was $3,353 million. As a result of the CODI and in accordance with IRC rules, the Company reduced its gross federal net operating loss (NOL) carryovers $3,015 million, its alternative minimum tax (AMT) credits $92 million, its capital loss carryforwards $59.2 million and the tax basis in certain assets $3.2 million. The Company was able to retain $931.1 million of gross federal NOLs, $22.8 million of AMT credit and $5.9 million of capital loss carryforwards following the bankruptcy.

Due to changes in ownership that occurred in connection with the Company's emergence from bankruptcy, there was a change in ownership for purposes of IRC Section 382. Section 382 provides a combined annual limitation with respect to the ability of a corporation to use its NOLs, AMT credits and capital loss carryforwards generated before the ownership change against future taxable income. The Company's annual limit under IRC section 382 is estimated to be $29.8 million. The Company had a net unrealized built-in gain at the time of the ownership change, therefore, certain built-in gains recognized within five years after the ownership change will increase the annual IRC section 382 limit for the five year recognition period beginning October 1, 2016 through September 30, 2021. There is significant uncertainty surrounding which assets with built-in gain will be realized within the five year period following the Company's emergence from bankruptcy and allow the Company to realize the incremental net operating losses and credit in excess of the base 382 limitation. The Company is reflecting a deferred tax asset for the full amount of the net operating losses and credit carryforwards. If at some point in time it becomes evident that some portion of the deferred tax assets will not be realizable, the deferred tax asset, and offsetting valuation allowance will be reduced.

The Company is subject to U.S. federal income tax as well as income tax in multiple state jurisdictions. The tax years 2002 through 2016 remain open to examination for U.S. federal income tax matters and 2004 through 2016 remain open to examination for various state income tax matters.

Significant components of the provision for (benefit from) income taxes are as follows:

	Successor	Predecessor		
(In thousands)	**October 2 through December 31, 2016**	**January 1 through October 1, 2016**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Current:				
Federal	$ —	$ —	$ —	$ —
State	(252)	7	3	25
Total current	(252)	7	3	25
Deferred:				
Federal	1,352	(4,720)	(329,393)	18,535
State	56	87	(43,990)	7,074
Total deferred	1,408	(4,633)	(373,383)	25,609
	$ 1,156	$ (4,626)	$ (373,380)	$ 25,634

A reconciliation of the statutory federal income tax provision (benefit) at the statutory rate to the actual provision for (benefit from) income taxes follows:

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(In thousands)				
Income tax provision (benefit) at statutory rate	$ 12,112	$ 433,109	$ (1,150,283)	$ (186,452)
Percentage depletion allowance	(4,292)	(3,681)	(19,035)	(12,692)
State taxes, net of effect of federal taxes	633	(46,122)	(76,445)	(3,903)
Reversal of cancellation of indebtedness income	—	(1,493,162)	—	—
Worthless stock deduction	—	(80,077)	—	—
Change in valuation allowance	(7,655)	1,185,326	865,146	226,929
Other, net	358	(19)	7,237	1,752
	$ 1,156	$ (4,626)	$ (373,380)	$ 25,634

Significant components of the Company's deferred tax assets and liabilities that result from carryforwards and temporary differences between the financial statement basis and tax basis of assets and liabilities are summarized as follows:

	Successor	Predecessor
	December 31, 2016	December 31, 2015
(In thousands)		
Deferred tax assets:		
Net operating loss carryforwards	$ 376,293	$ 1,086,332
Alternative minimum tax credit carryforwards	22,798	120,994
Investment in tax partnerships & corporations	604,914	—
Reclamation and mine closure	—	121,276
Goodwill	5,135	38,671
Workers' compensation	—	42,835
Share based compensation	—	22,612
Sales contracts	—	17,466
Retiree benefit plans	4,013	16,996
Advance royalties	—	18,751
Losses from disposed operations resulting from Patriot Coal bankruptcy	—	39,287
Other, primarily accrued liabilities	30,103	45,303
Gross deferred tax assets	1,043,256	1,570,523
Valuation allowance	(1,021,553)	(1,135,399)
Total deferred tax assets	21,703	435,124
Deferred tax liabilities:		
Plant and equipment	7,332	389,169
Deferred development	—	41,047
Sales contracts	12,658	—
Other	1,600	4,706
Total deferred tax liabilities	21,590	434,922
Net deferred (asset) liability	(113)	(202)

The Company has gross federal net operating loss carryforwards for regular income tax purposes of $931.1 million at December 31, 2016 that will expire between 2022 and 2036. The Company has an alternative minimum tax credit carryforward of $22.8 million at December 31, 2016, which has no expiration date and can be used to offset future regular tax in excess of the alternative minimum tax. The future annual usage of NOLs and AMT credit will be limited under IRC section 382.

As part of our efforts to create operational efficiency leading up to and through the bankruptcy process, we have consolidated our mining operations and land management into a partnership structure to match our legal form with the Company's streamlined operations during 2016. As such, deferred taxes related to those operations are now reported based upon the book and tax outside basis difference in the partnership interests as provided in ASC 740-30-25-7, which results in a different basis of presentation that was used in 2015 under our prior legal structure.

As recent cumulative losses constitute significant negative evidence with regards to future taxable income, the Company has relied solely on the expected reversal of taxable temporary differences to support the future realization of its deferred tax assets. The Company performs a detailed scheduling process of its net taxable temporary differences.

At December 31, 2014, all deductible temporary differences were expected to be realized as there were sufficient deferred tax liabilities within the same jurisdiction and of the same character that are available to offset them. Valuation allowances were established for federal and state net operating losses and tax credits that were not offset by the reversal of other net taxable temporary differences before the expiration of the attribute.

At December 31, 2015, additional losses were realized relating primarily to financial conditions and asset impairment charges. As a result, the expected reversal of taxable temporary differences were not sufficient to support the future realization of the deferred tax assets and an additional $865.1 million valuation allowance was recorded. Net deferred tax assets of $1,135 million were completely offset by a valuation allowance.

At December 31, 2016, additional tax losses were realized primarily as a result of the non-recognition of CODI under section 108 of the IRC by the Predecessor entity. As a result, the expected reversal of taxable temporary differences were not sufficient to support the future realization of the deferred tax assets and an additional $1,185 million valuation allowance was recorded to the provision. Offsetting this increase was a net reduction in the valuation allowance of $1,289 million which did not impact the provision. This reduction was primarily the result of a decrease in NOLs and AMT credits due to the IRC section 108 offset rules. Net deferred tax assets of $1,022 million are completely offset by a valuation allowance.

A reconciliation of the beginning and ending amounts of gross unrecognized tax benefits follows:

			(In thousands)
Balance at	January 1, 2014	$	31,789
Additions based on tax positions related to the current year			2,920
Balance at	December 31, 2014		34,709
Additions based on tax positions related to the current year			4,168
Balance at	December 31, 2015		38,877
Additions for tax positions of prior years			2,979
Additions for tax positions related to the current year			2,709
Reductions as a result of bankruptcy			(37,110)
Balance at	December 31, 2016	$	7,455

If recognized, the entire amount of the gross unrecognized tax benefits at December 31, 2016 would affect the effective tax rate.

As a result of the bankruptcy, federal and state governments are precluded from assessing additional tax in audits of tax periods ending prior to bankruptcy. As a result, the Company has released $37.1 million of gross unrecognized tax benefits for years 2015 and prior. These gross unrecognized tax benefits are fully offset by a corresponding release in valuation allowance.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company had accrued interest and penalties of $0.5 million and $1.7 million at December 31, 2016 and 2015, respectively. In the next 12 months, no gross unrecognized tax benefits are expected to be reduced due to the expiration of the statute of limitations.

15. Asset Retirement Obligations

The Company's asset retirement obligations arise from the Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. The required reclamation activities to be performed are outlined in the Company's mining permits. These activities include reclaiming the pit and support acreage at surface mines, sealing portals at underground mines, and reclaiming refuse areas and slurry ponds.

The following table describes the changes to the Company's asset retirement obligation liability:

	Successor	Predecessor	
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015
(In thousands)			
Balance at beginning of period (including current portion)	$ 354,326	$ 410,454	$ 418,118
Accretion expense	7,634	24,321	33,680
Obligations of divested operations	—	(14,702)	(334)
Adjustments to the liability from changes in estimates	—	3,003	(28,570)
Liabilities settled	(5,218)	(11,087)	(12,440)
Fresh start accounting adjustment	—	(57,663)	—
Balance at period end	$ 356,742	$ 354,326	$ 410,454
Current portion included in accrued expenses	(19,515)	(17,290)	(13,795)
Noncurrent liability	$ 337,227	$ 337,036	$ 396,659

As of December 31, 2016, the Company had $528.3 million in surety bonds outstanding and $21.3 million in letters of credit to secure reclamation bonding obligations. Additionally, the Company has posted $33.4 million in cash as collateral related to reclamation surety bonds; this amount is recorded within "Noncurrent assets" on the Consolidated Balance Sheet.

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16. **Fair Value Measurements**

The hierarchy of fair value measurements assigns a level to fair value measurements based on the inputs used in the respective valuation techniques. The levels of the hierarchy, as defined below, give the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs.

· Level 1 is defined as observable inputs such as quoted prices in active markets for identical assets. Level 1 assets include available-for-sale equity securities, U.S. Treasury securities, and coal swaps and futures that are submitted for clearing on the New York Mercantile Exchange.

· Level 2 is defined as observable inputs other than Level 1 prices. These include quoted prices for similar assets or liabilities in an active market, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. The Company's level 2 assets and liabilities include U.S. government agency securities and coal commodity contracts with fair values derived from quoted prices in over-the-counter markets or from prices received from direct broker quotes.

· Level 3 is defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. These include the Company's commodity option contracts (coal and heating oil) valued using modeling techniques, such as Black-Scholes, that require the use of inputs, particularly volatility, that are rarely observable. Changes in the unobservable inputs would not have had a significant impact on the reported Level 3 fair values at December 31, 2016 and 2015.

The table below sets forth, by level, the Company's financial assets and liabilities that are recorded at fair value in the accompanying consolidated balance sheet:

	Successor			
	Fair Value at December 31, 2016			
	Total	Level 1	Level 2	Level 3
	(In thousands)			
Assets:				
Investments in marketable securities	$ 90,209	$ 2,137	$ 88,072	$ —
Derivatives	4,908	262	—	4,646
Total assets	$ 95,117	$ 2,399	$ 88,072	$ 4,646
Liabilities:				
Derivatives	$ 101	$ (8)	$ —	$ 109

	Predecessor			
	Fair Value at December 31, 2015			
	Total	Level 1	Level 2	Level 3
	(In thousands)			
Assets:				
Investments in marketable securities	$ 201,910	$ 11,713	$ 190,197	$ —
Derivatives	9,052	5,597	1,023	2,432
Total assets	$ 210,962	$ 17,310	$ 191,220	$ 2,432
Liabilities:				
Derivatives	$ —	$ —	$ —	$ —

The Company's contracts with its counterparties allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. For classification purposes, the Company records the net fair value of all the positions with these counterparties as a net asset or liability. Each level in the table above displays the underlying contracts according to their classification in the accompanying consolidated balance sheet, based on this counterparty netting.

The following table summarizes the change in the fair values of financial instruments categorized as level 3.

	Successor	Predecessor	
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015
	(In thousands)	(In thousands)	
Balance, beginning of period	$ 3,842	$ 2,432	$ 3,040
Realized and unrealized losses recognized in earnings, net	926	(1,686)	(8,602)
Included in other comprehensive income	—	—	(1,341)
Purchases	1,225	5,021	13,541
Issuances	(34)	(488)	(4,046)
Settlements	(1,422)	(1,437)	(160)
Ending balance	$ 4,537	$ 3,842	$ 2,432

Net unrealized gains of $0.4 million were recognized during the period October 2 through December 31, 2016 related to level 3 financial instruments held on December 31, 2016.

Cash and Cash Equivalents

At December 31, 2016 and 2015, the carrying amounts of cash and cash equivalents approximate their fair value.

Fair Value of Long-Term Debt

At December 31, 2016 and 2015, the fair value of the Company's debt, including amounts classified as current, was $362.9 million and $937.1 million, respectively. Fair values are based upon observed prices in an active market, when available, or from valuation models using market information, which fall into Level 2 in the fair value hierarchy.

17. Capital Stock

Successor Company

Equity Securities

Under the Plan, 24,589,834 shares of Class A Common Stock and 410,166 shares of Class B Common Stock, par value $.01 per share, were distributed to the secured lenders and to certain holders of general unsecured claims under the Plan on the Effective Date. The Class A Common Stock and Class B Common stock are identical in all respects except that Class B Common Stock shall not be listed by the Company on any national securities exchange registered under Section 6 of the Securities Exchange Act of 1934, as amended. In addition, on the Effective Date, Arch Coal issued Warrants to purchase up to an aggregate of 1,914,856 shares of Class A Common Stock. Arch Coal relied, based on the confirmation order it received from the Bankruptcy Court, on Section 1145(a)(1) of the U.S. Bankruptcy Code to exempt from the registration requirements of the Securities Act of 1933, as amended (i) the offer and sale of Common Stock to the secured lenders and to the general unsecured creditors, (ii) the offer and sale of the Warrants to the holders of claims arising under the Cancelled Notes and (iii) the offer and sale of the Class A Common Stock issuable upon exercise of the Warrants. Section 1145(a)(1) of the Bankruptcy Code exempts the offer and sale of securities under a plan of reorganization from registration under Section 5 of the Securities Act and state laws if three principal requirements are satisfied:

- the securities must be offered and sold under a plan of reorganization and must be securities of the debtor, of an affiliate participating in a joint plan of reorganization with the debtor or of a successor to the debtor under the plan of reorganization;
- the recipients of the securities must hold claims against or interests in the debtor; and
- the securities must be issued in exchange, or principally in exchange, for the recipient's claim against or interest in the debtor.

See Note 3, "Emergence from Bankruptcy and Fresh Start Accounting" for additional information.

Outstanding Warrants

As of December 31, 2016, holders of warrants had exercised 2,871 of the warrants.

As provided in ASC 825-20, “Financial Instruments,” the warrants are considered equity because they can only be physically settled in Company shares, can be settled in unregistered shares, the Company has adequate authorized shares to settle the outstanding warrants and each warrant is fixed in terms of settlement to one share of Company stock subject only to remote contingency adjustment factors designed to assure the relative value in terms of shares remains fixed.

Predecessor Company

Reverse Stock Split

On August 4, 2015, the Company effected a 1-for-10 reverse stock split of our common stock. Each stockholder’s percentage ownership and proportional voting power remain unchanged as a result of the reverse stock split. All applicable share data, per share amounts and related information in the Consolidated Financial Statements and notes thereto have been adjusted retroactively to give effect to the 1-for-10 reverse stock split.

18. **Stock-Based Compensation and Other Incentive Plans**

Successor Company

Under the Company’s 2016 Omnibus Incentive Plan (the “Incentive Plan”), 3.0 million shares of the Company’s common stock were reserved for awards to officers and other selected key management employees of the Company. The Incentive Plan provides the Board of Directors with the flexibility to grant stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance stock or units, phantom stock awards and rights to acquire stock through purchase under a stock purchase program (“Awards”). Awards the Board of Directors elects to pay out in cash do not impact the shares authorized in the Incentive Plan. Shares available for award under the plan were 2.6 million at December 31, 2016.

Restricted Stock Unit Awards

The Company may issue restricted stock and restricted stock units, which require no payment from the employee. Restricted stock cliff-vests at various dates and restricted stock units either vest ratably over or vest at the end of the award’s stated vesting period. Compensation expense is based on the fair value on the grant date and is recorded ratably over the vesting period utilizing the straight-line recognition method. The employee receives cash compensation equal to the amount of dividends that would have been paid on the underlying shares.

Three restricted stock unit awards were granted in the Successor period: two time based awards vesting over one and three years: and one performance based award vesting over a three year period. The time based awards’ grant date fair value was determined based on the stock price at the date of grant. The performance award’s grant date fair value was determined using a Monte Carlo simulation. A volatility of 58% was selected based on comparator companies, and the three year risk free rate was derived from yields on U.S. Government bonds. Information regarding the restricted stock units activity and weighted average grant-date fair value follows:

(Shares in thousands)	Common Shares	Weighted Average Grant-Date Fair Value
Outstanding at October 2, 2016	—	—
Granted	384	$ 72.00
Forfeited	—	—
Canceled	—	—
Unvested outstanding at December 31, 2016	384	$ 72.00

The Company recognized expense related to restricted stock units for the period October 2, 2016 through December 31, 2016 of $1.0 million.

Long-Term Incentive Compensation

The Company has a long-term incentive program that allows for the award of performance units. The total number of units earned by a participant is based on financial and operational performance measures, and may be paid out in cash or in shares of the Company’s common stock. The Company recognizes compensation expense over the three year term of the grant. The liabilities are remeasured quarterly. The Company recognized expense of $1.6 million for the period October 2 through December 31, 2016, $7.2 million for the period January 1 through October 1, 2016, and $7.9 million and $10.1 million for the years ended December 31, 2015 and 2014, respectively. The expense is included primarily in "Selling, general and administrative expenses" in the accompanying consolidated statements of operations.

As part of the plan of reorganization, the Company's Executive Officers agreed to a $6.0 million reduction in scheduled compensation payouts in 2017. The long term incentive compensation liability was reduced $3.7 million as a fresh start accounting adjustment and is reflected in the Successor period ending December 31, 2016 balance. Amounts accrued and unpaid for all grants under the plan totaled $13.9 million and $17.8 million as of December 31, 2016 and 2015, respectively.

Predecessor Company

On the Effective Date, all shares of our old common stock, including any vested and unvested stock options, restricted stock and restricted stock units were canceled.

Common Stock

Stock options are granted at a strike price equal to the closing market price of the Company's common stock on the date of grant and are generally subject to vesting provisions of a least one year from the date of grant. Compensation expense related to stock options for the period January 1, 2016 through October 1, 2016, and for the years ended 2015 and 2014 were $0.2 million, $1.4 million and $3.2 million, respectively. The majority of the cost relating to the stock-based compensation plans is included in "Selling, general and administrative expenses" in the accompanying consolidated statements of operations.

Restricted stock units

The company may issue restricted stock and restricted stock units, which require no payment from the employee. Restricted stock cliff-vests at various dates and restricted stock units either vest ratably over or vest at the end of three years. Compensation expense is based on the fair value on the grant date and is recorded ratably over the vesting period. Compensation expense related to restricted stock and restricted stock units for the period January 1, 2016 through October 1, 2016, and for the years ended 2015 and 2014 were $1.9 million, $5.9 million and $5.6 million, respectively. The majority of the cost relating to the stock-based compensation plans is included in "Selling, general and administrative expenses" in the accompanying consolidated statements of operations.

19. **Workers' Compensation Expense**

The Company is liable under the Federal Mine Safety and Health Act of 1969, as subsequently amended, to provide for pneumoconiosis (occupational disease) benefits to eligible employees, former employees and dependents. The Company currently provides for federal claims principally through a self-insurance program. The Company is also liable under various state workers' compensation statutes for occupational disease benefits. The occupational disease benefit obligation represents the present value of the of the actuarially computed present and future liabilities for such benefits over the employees' applicable years of service.

In addition, the Company is liable for workers' compensation benefits for traumatic injuries which are calculated using actuarially-based loss rates, loss development factors and discounted based on a risk free rate of 1.74%. Traumatic workers' compensation claims are insured with varying retentions/deductibles, or through state-sponsored workers' compensation programs.

Workers' compensation expense consists of the following components:

	Successor	Predecessor		
(In thousands)	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Self-insured occupational disease benefits:				
Service cost	$ 1,583	$ 3,465	$ 4,282	$ 1,734
Interest cost	1,126	3,184	3,944	2,914
Net amortization	—	4,325	6,973	(216)
Total occupational disease	$ 2,709	$ 10,974	$ 15,199	$ 4,432
Traumatic injury claims and assessments	3,162	6,628	16,781	19,924
Total workers' compensation expense	$ 5,871	$ 17,602	$ 31,980	$ 24,356

The table below reconciles changes in the occupational disease liability for the respective period.

	Successor	Predecessor	
(In thousands)	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015
Beginning of period	$ 119,710	$ 90,836	$ 72,749
Service cost	1,583	3,465	4,282
Interest cost	1,126	3,184	3,944
Curtailments	—	4,156	
Actuarial (gain) loss	(9,675)	—	14,284
Benefit and administrative payments	(1,585)	(3,728)	(4,423)
Fresh start accounting adjustment	—	21,797	—
	$ 111,159	$ 119,710	$ 90,836

The following table provides the assumptions used to determine the projected occupational disease obligation:

	Successor	Predecessor	
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015
(Percentages)			
Occupational Disease Benefit			
Discount rate	4.31	3.80	4.76
Cost escalation rate	N/A	N/A	N/A

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for workers' compensation benefits:

	Successor	Predecessor
	Year Ended December 31, 2016	Year Ended December 31, 2015
(In thousands)		
Occupational disease costs	$ 111,159	$ 90,836
Traumatic and other workers' compensation claims	88,593	38,309
Total obligations	199,752	129,145
Less amount included in accrued expenses	15,184	16,875
Noncurrent obligations	$ 184,568	$ 112,270

As of December 31, 2016, the Company had $146.2 million in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

The Company's recorded liabilities include $19.4 million of obligations that are reimbursable under various insurance policies purchased by the company. These insurance receivables are recorded in the balance sheet line items "Other receivables" and "Other noncurrent assets" for $0.8 million and $18.6 million.

20. **Employee Benefit Plans**

Defined Benefit Pension and Other Postretirement Benefit Plans

The Company provides funded and unfunded non-contributory defined benefit pension plans covering certain of its salaried and hourly employees. Benefits are generally based on the employee's age and compensation. The Company funds the plans in an amount not less than the minimum statutory funding requirements or more than the maximum amount that can be deducted for U.S. federal income tax purposes.

The Company also currently provides certain postretirement medical and life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement benefit plans are contributory, with retiree contributions adjusted annually, and contain other cost-sharing features such as deductibles and coinsurance. The Company's current funding policy is to fund the cost of all postretirement benefits as they are paid.

The idling of the Cumberland River mining operations in Appalachia in the third quarter of 2014 reduced the estimated years of future service for the CRCC Scotia Employee Association Pension Plan. On January 1, 2015, the Company's cash balance and excess plans were amended to freeze new service credits for any new or active employee. These two events triggered curtailment accounting, resulting in an immediate recognition of any unamortized gain or loss and the reduction in the projected benefit obligation which were recorded in the third and fourth quarter of 2014, respectively.

Obligations and Funded Status.

Summaries of the changes in the benefit obligations, plan assets and funded status of the plans are as follows:

(In thousands)	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015
CHANGE IN BENEFIT OBLIGATIONS						
Benefit obligations at beginning of period	$ 341,427	$ 301,292	$ 353,736	$ 120,311	$ 103,460	$ 36,098
Service cost	—	—	9	180	393	866
Interest cost	2,768	9,338	14,604	978	3,223	1,904
Re-entry of former Magnum employees	—	—	—	—	—	85,843
Settlements	(135)	—	—	—	—	—
Curtailments	—	454	—	—	714	—
Benefits paid	(11,009)	(8,699)	(61,955)	(1,962)	(8,273)	(3,646)
Other-primarily actuarial gain	(19,422)	—	(5,102)	(7,640)	—	(17,605)
Fresh start accounting adjustments	—	39,042	—	—	20,794	
Benefit obligations at end of period	$ 313,629	$ 341,427	$ 301,292	$ 111,867	$ 120,311	$ 103,460
CHANGE IN PLAN ASSETS						
Value of plan assets at beginning of period	$ 292,726	$ 273,499	$ 336,709	$ —	$ —	$ —
Actual return on plan assets	(7,899)	27,811	(1,679)		—	—
Employer contributions	407	115	424	1,962	8,273	3,646
Benefits paid	(11,009)	(8,699)	(61,955)	(1,962)	(8,273)	(3,646)
Value of plan assets at end of period	$ 274,225	$ 292,726	$ 273,499	$ —	$ —	$ —
Accrued benefit cost	$ (39,404)	$ (48,701)	$ (27,793)	$ (111,867)	$ (120,311)	$ (103,460)
ITEMS NOT YET RECOGNIZED AS A COMPONENT OF NET PERIODIC BENEFIT COST						
Prior service credit (cost)	$ —	$ —	$ —	$ —	$ —	$ 26,944
Accumulated gain (loss)	6,751	—	(16,769)	7,640	—	11,313
	$ 6,751	$ —	$ (16,769)	$ 7,640	$ —	$ 38,257
BALANCE SHEET AMOUNTS						
Current liability	$ (520)	$ (420)	$ (420)	$ (10,422)	$ (8,352)	$ (3,650)
Noncurrent liability	(38,884)	(48,281)	$ (27,373)	(101,445)	(111,959)	(99,810)
	$ (39,404)	$ (48,701)	$ (27,793)	$ (111,867)	$ (120,311)	$ (103,460)

Pension Benefits

The accumulated benefit obligation for all pension plans was $313.6 million and $301.3 million at December 31, 2016 and 2015, respectively.

Due to the Company adopting the corridor method of amortizing actuarial gains (losses) during fresh start accounting, it is anticipated there will be no amortization recorded into net periodic benefit cost during 2017.

Other Postretirement Benefits

Due to the Company adopting the corridor method of amortizing actuarial gains (losses) during fresh start accounting, it is anticipated there will be no amortization recorded into net periodic benefit cost during 2017.

Components of Net Periodic Benefit Cost. The following table details the components of pension and postretirement benefit costs (credits):

	Pension Benefits				Other Postretirement Benefits			
	Successor	Predecessor			Successor	Predecessor		
(In thousands)	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Service cost	$ —	$ —	$ 9	$ 21,478	$ 180	$ 393	$ 866	$ 1,649
Interest cost	2,768	9,338	14,604	17,070	978	3,223	1,904	1,841
Curtailments	—	454	—	(25,368)	—	(970)	—	—
Settlements	(135)	—	2,656	646	—	—	—	—
Expected return on plan assets	(4,770)	(13,623)	(20,367)	(23,756)	—	—	—	—
Amortization of prior service credits	—	—	—	(257)	—	(7,854)	(8,335)	(10,003)
Amortization of other actuarial losses (gains)	—	3,973	8,850	3,128	—	(849)	(2,109)	(761)
Net benefit cost (credit)	$ (2,137)	$ 142	$ 5,752	$ (7,059)	$ 1,158	$ (6,057)	$ (7,674)	$ (7,274)

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings over the remaining service attribution periods of the employees using the corridor method.

Assumptions. The following table provides the weighted average assumptions used to determine the actuarial present value of projected benefit obligations for the respective periods.

	Successor	Predecessor	
(Percentages)	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015
Pension Benefits			
Discount rate	3.95	3.39	4.59
Rate of compensation increase	N/A	N/A	N/A
Other Postretirement Benefits			
Discount rate	3.93	3.37	4.57
Rate of compensation increase	N/A	N/A	N/A

The following table provides the weighted average assumptions used to determine net periodic benefit cost for the respective periods.

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(Percentages)				
Pension Benefits				
Discount rate	3.39/3.95	4.59/3.80	4.15/4.61/4.41/4.60	5.08/4.23/4.14
Rate of compensation increase	N/A	N/A	N/A	N/A
Expected return on plan assets	6.85	6.85	7.00	7.75
Other Postretirement Benefits				
Discount rate	3.37	4.57/3.80	3.91	4.58
Rate of compensation increase	N/A	N/A	N/A	N/A
Expected return on plan assets	N/A	N/A	N/A	N/A

The discount rates used in 2016, 2015 and 2014 were reevaluated during the year for settlements and curtailments. The obligations are remeasured at an updated discount rate that impacts the benefit cost recognized subsequent to the remeasurement.

The Company establishes the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The Company utilizes modern portfolio theory modeling techniques in the development of its return assumptions. This technique projects rates of return that can be generated through various asset allocations that lie within the risk tolerance set forth by members of the Company's pension committee (the "Pension Committee"). The risk assessment provides a link between a pension plan's risk capacity, management's willingness to accept investment risk and the asset allocation process, which ultimately leads to the return generated by the invested assets.

The health care cost trend rate assumed for 2017 is 6.7% and is expected to reach an ultimate trend rate of 4.5% by 2038. A one-percentage-point increase in the health care cost trend rate would increase the postretirement benefit obligation at December 31, 2016 by $11.1 million and the net periodic postretirement benefit cost for the year ended December 31, 2016 by $0.1 million.

Plan Assets

The Pension Committee is responsible for overseeing the investment of pension plan assets. The Pension Committee is responsible for determining and monitoring appropriate asset allocations and for selecting or replacing investment managers, trustees and custodians. The pension plan's current investment targets are 55% equity and 45% fixed income securities. The Pension Committee reviews the actual asset allocation in light of these targets on a periodic basis and rebalances among investments as necessary. The Pension Committee evaluates the performance of investment managers as compared to the performance of specified benchmarks and peers and monitors the investment managers to ensure adherence to their stated investment style and to the plan's investment guidelines.

The Company’s pension plan assets at December 31, 2016 and 2015, respectively, are categorized below according to the fair value hierarchy as defined in Note 16, “Fair Value Measurements”:

	Total		Level 1		Level 2		Level 3	
	2016	2015	2016	2015	2016	2015	2016	2015
				(In thousands)				
Equity Securities:[A]								
U.S. small-cap	$ 13,520	$ 11,640	$ 13,520	$ 11,640	$ —	$ —	$ —	$ —
U.S. mid-cap	29,687	28,524	9,422	10,979	20,265	17,545	—	—
U.S. large-cap	70,226	67,244	34,107	33,249	36,119	33,995	—	—
Non-U.S.	18,937	18,785	—	—	18,937	18,785	—	—
Fixed income securities:								—
U.S. government securities[B]	26,519	18,844	19,973	18,183	6,546	661	—	—
Non-U.S. government securities[C]	1,567	766	—	—	1,567	766	—	—
U.S. government asset and mortgage backed securities[D]	1,074	1,056	—	—	1,074	1,056	—	—
Corporate fixed income[E]	58,191	39,939	—	—	58,191	39,939	—	—
State and local government securities[F]	6,406	5,725	—	—	6,406	5,725	—	—
Other investments[I]	26,151	19,869	—	—	6,910	1,234	19,241	18,635
Total	$ 252,278	$ 212,392	$ 77,022	$ 74,051	$ 156,015	$ 119,706	$ 19,241	$ 18,635
Other fixed income[G]	35,519							
Short-term investments[H]	8,598							
Other liabilities[J]	(22,170)							
	$ 274,225							

[A] Equity securities includes investments in 1) common stock, 2) preferred stock and 3) mutual funds. Investments in common and preferred stocks are valued using quoted market prices multiplied by the number of shares owned. Investments in mutual funds are valued at the net asset value per share multiplied by the number of shares held as of the measurement date and are traded on listed exchanges.

[B] U.S. government securities includes agency and treasury debt. These investments are valued using dealer quotes in an active market.

[C] Non-U.S. government securities includes debt securities issued by foreign governments and are valued utilizing a price spread basis valuation technique with observable sources from investment dealers and research vendors.

[D] U.S. government asset and mortgage backed securities includes government-backed mortgage funds which are valued utilizing an income approach that includes various valuation techniques and sources such as discounted cash flows models, benchmark yields and securities, reported trades, issuer trades and/or other applicable data.

[E] Corporate fixed income is primarily comprised of corporate bonds and certain corporate asset-backed securities that are denominated in the U.S. dollar and are investment-grade securities. These investments are valued using dealer quotes.

[F] State and local government securities include different U.S. state and local municipal bonds and asset backed securities, these investments are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes, benchmark yields and securities, reported trades, issuer trades and/or other applicable data.

[G] Other fixed income investments are actively managed fixed income vehicles that are valued at the net asset value per share multiplied by the number of shares held as of the measurement date.

[H] Short-term investments include governmental agency funds, government repurchase agreements, commingled funds, and pooled funds and mutual funds. Governmental agency funds are valued utilizing an option adjusted spread valuation technique and sources such as interest rate generation processes, benchmark yields and broker quotes. Investments in governmental repurchase agreements, commingled funds and pooled funds and mutual funds are valued at the net asset value per share multiplied by the number of shares held as of the measurement date.

(I) Other investments include cash, forward contracts, derivative instruments, credit default swaps, interest rate swaps and mutual funds. Investments in interest rate swaps are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes in active and non-active markets, benchmark yields and securities, reported trades, issuer trades and/or other applicable data. Forward contracts and derivative instruments are valued at their exchange listed price or broker quote in an active market. The mutual funds are valued at the net asset value per share multiplied by the number of shares held as of the measurement date and are traded on listed exchanges.

(J) Net payable amount due for pending securities purchased and sold due to broker/dealer.

Cash Flows. The Company expects to make contributions of $0.4 million to the pension plans in 2017, which is impacted by the Moving Ahead for Progress in the 21st Century Act (MAP-21). MAP-21 does not reduce the Company's obligations under the plan, but redistributes the timing of required payments by providing near term funding relief for sponsors under the Pension Protection Act.

The following represents expected future benefit payments from the plan, which reflect expected future service, as appropriate:

	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2017	$ 19,403	$ 12,300
2018	21,117	12,716
2019	20,763	13,033
2020	21,209	13,408
2021	21,917	13,763
Next 5 years	102,619	64,920
	$ 207,028	$ 130,140

Other Plans

The Company sponsors savings plans which were established to assist eligible employees in providing for their future retirement needs. The Company's expense, representing its contributions to the plans, was $3.5 million for the period October 2 through December 31, 2016, $13.8 million for the period January 1 through October 1, 2016 and $20.5 million and $22.9 million for the years ended December 31, 2015 and 2014, respectively.

21. **Earnings (Loss) Per Common Share**

The Company computes basic net income per share using the weighted average number of common shares outstanding during the period. Diluted net income per share is computed using the weighted average number of common shares and the effect of potentially dilutive securities outstanding during the period. Potentially dilutive securities may consist of warrants, restricted stock units or other contingently issuable shares. The dilutive effect of outstanding warrants, restricted stock units and other contingently issuable shares is reflected in diluted earnings per shares by application of the treasury stock method.

The following table provides the basis for basic and diluted EPS by reconciling the numerators and denominators of the computations:

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(In Thousands)				
Weighted average shares outstanding:				
Basic weighted average shares outstanding	25,002	21,293	21,285	21,222
Effect of dilutive securities	467	20	—	—
Diluted weighted average shares outstanding	25,469	21,313	21,285	21,222

22. **Leases**

The Company leases equipment, land and various other properties under non-cancelable long-term leases, expiring at various dates. Certain leases contain options that would allow the Company to extend the lease or purchase the leased asset at the end of the base lease term.

In addition, the Company enters into various non-cancelable royalty lease agreements under which future minimum payments are due.

Minimum payments due in future years under these agreements in effect at December 31, 2016 are as follows:

	Operating Leases	Royalties
	(In thousands)	
2017	$ 14,653	$ 3,994
2018	14,485	6,021
2019	5,321	6,105
2020	2,260	7,147
2021	1,985	7,809
Thereafter	10,317	46,499
	$ 49,021	$ 77,575

Obligations for the future minimum payments under capital leases for equipment totaling $0.0 million and $40.0. million at December 31, 2016 and 2015, respectively, are included in other long term debt obligations in Note 13, “Debt and Financing Arrangements”.

Rental expense, including amounts related to these operating leases and other shorter-term arrangements, amounted to $5.0 million for the period October 2 through December 31, 2016, $19.4 million for the period January 1 through October 1, 2016, $28.4 million in 2015 and $42.1 million in 2014.

Royalties are paid to lessors either as a fixed price per ton or as a percentage of the gross selling price of the mined coal. Royalties under the majority of the Company’s significant leases are paid on the percentage of gross selling price basis. Royalty expense, including production royalties, was $45.3 million for the period October 2 through December 31, 2016, $116.4 million for the period January 1 through October 1, 2016, $227.7 million in 2015 and $242.5 million in 2014.

As of December 31, 2016, certain of the Company’s lease obligations were secured by outstanding surety bonds totaling $32.6 million.

23. **Risk Concentrations**

Credit Risk and Major Customers

The Company has a formal written credit policy that establishes procedures to determine creditworthiness and credit limits for trade customers and counterparties in the over-the-counter coal market. Generally, credit is extended based on an evaluation of the customer’s financial condition. Collateral is not generally required, unless credit cannot be established. Credit losses are provided for in the financial statements and historically have been minimal.

The Company markets its steam coal principally to domestic and foreign electric utilities and its metallurgical coal to domestic and foreign steel producers. As of December 31, 2016 and 2015, accounts receivable from electric utilities of $96.0 million and $83.8 million, respectively, represented 52% and 72% of total trade receivables at each date. As of December 31, 2016 and 2015, accounts receivable from sales of metallurgical-quality coal of $88.0 million and $32.8 million, respectively, represented 48% and 28% of total trade receivables at each date.

The Company uses shipping destination as the basis for attributing revenue to individual countries. Because title may transfer on brokered transactions at a point that does not reflect the end usage point, they are reflected as exports, and attributed to an end delivery point if that knowledge is known to the Company. The Company’s foreign revenues by geographical location are as follows:

	Successor	Predecessor		
	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In thousands)	(In thousands)		
Europe	$ 61,408	$ 113,888	$ 170,314	$ 277,565
Asia	55,634	68,536	96,523	156,057
North America	43,831	56,594	40,315	78,445
Central and South America	13,224	41,861	55,323	20,496
Brokered Sales	—	—	32,848	79,354
Total	$ 174,097	$ 280,879	$ 395,323	$ 611,917

The Company is committed under long-term contracts to supply steam coal that meets certain quality requirements at specified prices. These prices are generally adjusted based on market indices. Quantities sold under some of these contracts may vary from year to year within certain limits at the option of the customer based on their requirements. The Company sold approximately 93.9 million tons of coal in 2016. Approximately 76% of this tonnage (representing approximately 62% of the Company's revenues) was sold under long-term contracts (contracts having a term of greater than one year). Long-term contracts range in remaining life from one to five years.

Third-party sources of coal

The Company uses independent contractors to mine coal at certain mining complexes. The Company also purchases coal from third parties that it sells to customers. Factors beyond the Company's control could affect the availability of coal produced for or purchased by the Company. Disruptions in the quantities of coal produced for or purchased by the Company could impair its ability to fill customer orders or require it to purchase coal from other sources at prevailing market prices in order to satisfy those orders.

Transportation

The Company depends upon barge, rail, truck and belt transportation systems to deliver coal to its customers. Disruption of these transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could temporarily impair the Company's ability to supply coal to its customers In the past, disruptions in rail service have resulted in missed shipments and production interruptions.

24. **Commitments and Contingencies**

The Company accrues for cost related to contingencies when a loss is probable and the amount is reasonably determinable. Disclosure of contingencies is included in the financial statements when it is at least reasonably possible that a material loss or an additional material loss in excess of amounts already accrued may be incurred.

The Company is a party to numerous claims and lawsuits with respect to various matters. As of December 31, 2016 and 2015, the Company had accrued $2.2 million and $2.8 million, respectively, for all legal matters, including $2.2 million and $2.8 million, respectively, classified as current. The ultimate resolution of any such legal matter could result in outcomes which may be materially different from amounts the Company has accrued for such matters.

The Company has unconditional purchase obligations relating to purchases of coal, materials and supplies and capital commitments, other than reserve acquisitions, and is also a party to transportation capacity commitments. The future commitments under these agreements total $48.0 million in 2017, and is immaterial thereafter. The Company recognized expense relating to transportation capacity agreements of $1.6 million during the period January 1 through October 1, 2016; and $52.9 million and $36.5 million during the years ended December 31, 2015 and 2014, respectively.

25. **Segment Information**

The Company's reportable business segments are based on two distinct lines of business, metallurgical and thermal, and may include a number of mine complexes. The Company manages its coal sales by market, not by individual mining complex. Geology, coal transportation routes to customers, and regulatory environments also have a significant impact on the Company's marketing and operations management. 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 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. The Company used Adjusted EBITDAR to measure the operating performance of its segments and allocate resources to the segments. Furthermore, analogous measures are used by industry analysts to evaluate the Company's operating performance. Investors should be aware that the Company's presentation of Adjusted EBITDAR may not be comparable to similarly titled measures used by other companies. Upon emergence from bankruptcy, the Company updated its reportable segments to reflect the manner in which its Chief Operating Decision Maker (CODM) views the reorganized Company's business for purposes of reviewing performance and allocating resources. The Company now reports is results of operations primarily through the following reportable segments: Powder River Basin (PRB) segment containing the Company's primary thermal operations in Wyoming; the Metallurgical (MET) segment, containing the Company's metallurgical operations in West Virginia, Kentucky, and Virginia, and the Other Thermal segment containing the Company's supplementary thermal operations in Colorado, Illinois, and the Coal Mac thermal operation in West Virginia. Periods presented in this note have been recast for comparability.

Operating segment results for the Successor period October 2 through December 31, 2016 and the Predecessor periods January 1 through October 1, 2016 and the years ended December 31, 2015 and 2014 are presented below. The Company measures its segments based on "adjusted earnings before interest, taxes, depreciation, depletion, amortization, accretion on asset retirements obligations, and reorganization items, net (Adjusted EBITDAR)." Adjusted EBITDAR does not reflect mine closure or impairment costs, since those are not reflected in the operating income reviewed by management. See Note 5, "Impairment Charges and Mine Closure Costs" for discussion of these costs. The Corporate, Other and Eliminations grouping includes these charges, as well as the change in fair value of coal derivatives and coal trading activities, net; corporate overhead; land management activities; other support functions; and the elimination of intercompany transactions.

The asset amounts below represent an allocation of assets consistent with the basis used for the Company's incentive compensation plans. The amounts in Corporate, Other and Eliminations represent primarily corporate assets (cash, receivables, investments, plant, property and equipment) as well as unassigned coal reserves, above-market sales contracts and other unassigned assets.

(In thousands)	PRB	MET	Other Thermal	Corporate, Other and Eliminations	Consolidated
Successor Period **October 2 through December 31, 2016**					
Revenues	$ 275,703	$ 200,377	$ 97,382	$ 2,226	$575,688
Adjusted EBITDAR	55,765	30,819	31,159	(23,246)	94,497
Depreciation, depletion and amortization	9,949	18,287	3,911	457	32,604
Accretion on asset retirement obligation	5,049	528	540	1,517	7,634
Total assets	446,775	576,793	129,602	983,427	2,136,597
Capital expenditures	934	13,329	684	267	15,214
Predecessor Period **January 1 through October 1, 2016**					
Revenues	$ 726,747	$ 437,069	$ 213,052	$ 21,841	$1,398,709
Adjusted EBITDAR	113,185	11,851	31,448	(69,181)	87,303
Depreciation, depletion and amortization	100,151	55,311	32,310	3,809	191,581
Accretion on asset retirement obligation	16,940	1,765	1,988	3,628	24,321
Total assets	456,711	619,154	131,173	916,791	2,123,829
Capital expenditures	612	17,296	3,895	60,631	82,434
Predecessor Year Ended **December 31, 2015**					
Revenues	$ 1,448,440	$ 637,941	$ 428,809	$ 58,070	$ 2,573,260
Adjusted EBITDAR	281,039	70,450	42,734	(110,426)	283,797
Depreciation, depletion and amortization	176,257	133,463	47,786	21,839	379,345
Accretion on asset retirement obligation	22,156	2,267	2,658	6,599	33,680
Total assets	1,648,916	772,439	366,610	2,253,916	5,041,881
Capital expenditures	21,228	24,787	11,277	61,732	119,024
Predecessor Year Ended **December 31, 2014**					
Revenues	$ 1,490,377	$ 743,973	$ 535,783	$ 166,986	$ 2,937,119
Adjusted EBITDAR	218,731	112,719	78,238	(96,636)	313,052
Depreciation, depletion and amortization	168,522	163,644	52,991	33,591	418,748
Accretion on asset retirement obligation	20,748	2,089	2,412	7,660	32,909
Total assets	1,762,326	2,339,739	406,296	3,838,001	8,346,362
Capital expenditures	21,399	46,771	14,843	64,273	147,286

A reconciliation of segment Adjusted EBITDAR to consolidated income (loss) from continuing operations before income taxes follows:

	Successor	Predecessor		
(In thousands)	October 2 through December 31, 2016	January 1 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Adjusted EBITDAR	$ 94,497	$ 87,303	$ 283,797	$ 313,052
Depreciation, depletion and amortization	(32,604)	(191,581)	(379,345)	(418,748)
Accretion on asset retirement obligations	(7,634)	(24,321)	(33,680)	(32,909)
Amortization of sales contracts, net	(796)	728	8,811	13,187
Asset impairment and mine closure costs	—	(129,267)	(2,628,303)	(24,113)
Losses from disposed operations resulting from Patriot Coal bankruptcy	—	—	(116,343)	—
Interest expense, net	(10,754)	(133,235)	(393,549)	(383,188)
Net loss resulting from early retirement of debt and debt restructuring	—	(2,213)	(27,910)	—
Reorganization items, net	(759)	1,630,041	—	—
Fresh start coal inventory fair value adjustment	(7,345)	—	—	—
Income (loss) before income taxes	$ 34,605	$ 1,237,455	$ (3,286,522)	$ (532,719)

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26. Quarterly Selected Financial Data (unaudited)

	Predecessor				Successor
Year Ended December 31, 2016	**March 31**	**June 30**	**September 30**	**October 1**	**October 2 through December 31, 2016**
	(a) (b)	(a) (b)	(b)	(b)	
(In thousands, except per share data)					
Revenues	$ 428,106	$ 420,298	$ 550,305	—	575,688
Gross profit (loss)	$ (53,325)	$ (56,469)	$ 31,042	—	64,458
Asset impairment and mine closure costs	$ 85,520	$ 43,701	$ 46	—	—
Income (loss) from operations	$ (158,412)	$ (110,521)	$ 11,795	$ —	$ 46,118
Reorganization items, net	$ (3,875)	$ (21,271)	$ (20,904)	$ 1,676,091	$ (759)
Net income (loss)	$ (206,702)	$ (175,887)	$ (51,421)	$ 1,676,091	$ 33,449
Diluted earnings (loss) per common share	$ (9.71)	$ (8.26)	$ (2.41)	$ 78.66	$ 1.31

	Predecessor			
Year Ended December 31, 2015	**March 31**	**June 30**	**September 30**	**December 31**
		(a)	(a)	(a)
	(In thousands, except per share data)			
Revenues	$ 677,005	$ 644,462	$ 688,544	$ 563,249
Gross profit (loss)	$ 14,256	$ (16,507)	$ 47,275	$ (44,964)
Asset impairment and mine closure costs	$ —	$ 19,146	$ 2,120,292	$ 488,865
Loss from operations	$ (19,712)	$ (69,546)	$ (2,236,772)	$ (539,033)
Net loss	$ (113,195)	$ (168,103)	$ (1,999,476)	$ (632,368)
Diluted loss per common share	$ (5.32)	$ (7.93)	$ (93.91)	$ (29.70)

(a) Challenging coal markets resulted in impairment charges relating to mining and other operations, investments in equity method subsidiaries and prepaid mining royalties in 2016 and 2015. See further discussion in Note 5, "Impairment Charges and Mine Closure Costs " and Note 9, "Equity Method Investments and Membership Interests in Joint Ventures."

(b) The Company filed for bankruptcy on January 11, 2016 and subsequently emerged on October 5, 2016. See further discussion in Note 3, "Emergence from Bankruptcy and Fresh Start Accounting."

Schedule II

Arch Coal, Inc. and Subsidiaries
Valuation and Qualifying Accounts

	Balance at Beginning of Year	Additions (Reductions) Charged to Costs and Expenses	Charged to Other Accounts	Deductions [a]	Balance at End of Year
			(In thousands)		
Successor					
October 2 through December 31, 2016					
Reserves deducted from asset accounts:					
Accounts receivable and other receivables	$ —	$ —	$ —	$ —	$ —
Current assets — supplies and inventory	—	—	—	—	—
Deferred income taxes	1,033,982	(7,655)	—	—	1,026,327
Predecessor					
January 1 through October 1, 2016					
Reserves deducted from asset accounts:					
Accounts receivable and other receivables	$ 7,842	$ —	$ —	$ 7,842	$ —
Current assets — supplies and inventory	5,991	844	(5,060) [c]	1,775	—
Deferred income taxes	1,135,399	(101,417)		—	1,033,982
Year ended December 31, 2015					
Reserves deducted from asset accounts:					
Accounts receivable and other receivables	$ 159	$ 7,683	$ —	$ —	$ 7,842
Current assets — supplies and inventory	6,625	431	—	1,065	5,991
Deferred income taxes	270,251	865,148	—	—	1,135,399
Year ended December 31, 2014					
Reserves deducted from asset accounts:					
Accounts receivable and other receivables	$ 775	$ —	$ —	$ 616	$ 159
Current assets — supplies and inventory	8,446	580	(76) [b]	2,325	$ 6,625
Deferred income taxes	43,322	226,929	—	—	$ 270,251

(a) Reserves utilized, unless otherwise indicated.
(b) Disposition of subsidiaries
(c) Fresh start accounting adjustment

Exhibit 21.1

Subsidiaries of the Company

The following is a complete list of the direct and indirect subsidiaries of Arch Coal, Inc., a Delaware corporation, including their respective states of incorporation or organization, as of February 24, 2017:

Arch Coal Asia-Pacific PTE. LTD. (Singapore) 100%
- **Arch of Australia PTY LTD (Australia) 100%**
  - **Arch Coal Australia PTY LTD (Australia) 100%**
    - **Arch Coal Australia Holdings PTY LTD (Australia) 100%**

Arch Coal Europe Limited (Europe) 100%

Arch Coal Operations LLC (Delaware) 42.2%
- **Coal-Mac LLC (Kentucky) 100%**
- **Catenary Coal Holdings LLC (Delaware) 100%**
  - **Cumberland River Coal LLC (Delaware) 100%**
  - **Lone Mountain Processing LLC (Delaware) 100%**
    - **Powell Mountain Energy, LLC (Delaware) 100%**
- **ICG East Kentucky, LLC (Delaware) 100%**
- **ICG Eastern, LLC (Delaware) 100%**
- **ICG Illinois, LLC (Delaware) 100%**
- **ICG Tygart Valley, LLC (Delaware) 100%**
  - **Shelby Run Mining Company, LLC (Delaware) 100%**
- **Hunter Ridge LLC (Delaware) 100%**
  - **Bronco Mining Company LLC (West Virginia) 100%**
  - **Hawthorne Coal Company LLC (West Virginia) 100%**
  - **Hunter Ridge Coal LLC (Delaware) 100%**
  - **Juliana Mining Company LLC (West Virginia) 100%**
  - **King Knob Coal Co. LLC (West Virginia) 100%**
  - **Marine Coal Sales LLC (Delaware) 100%**
  - **Melrose Coal Company LLC (West Virginia) 100%**
  - **Patriot Mining Company LLC (West Virginia) 100%**
  - **Upshur Property LLC (Delaware) 100%**
  - **Vindex Energy LLC (West Virginia) 100%**
  - **White Wolf Energy LLC (Virginia) 100%**
  - **Wolf Run Mining Company LLC (West Virginia) 100%**
    - **The Sycamore Group, LLC (West Virginia) 50%**
- **Mingo Logan Coal LLC (Delaware) 100%**
- **Simba Group LLC (Delaware) 100%**

Arch Coal Sales Company, Inc. (Delaware) 100%
- **Arch Energy Resources, LLC (Delaware) 100%**

Arch Land LLC (Delaware) 57.6%
- **Ark Land LLC (Delaware) 100%**
  - **Western Energy Resources LLC (Delaware) 100%**
  - **Ark Land KH LLC (Delaware) 100%**
  - **Ark Land LT LLC (Delaware) 100%**
  - **Ark Land WR LLC (Delaware) 100%**
- **Allegheny Land LLC (Delaware) 100%**
- **Arch Coal West, LLC (Delaware) 100%**
- **Arch Reclamation Services LLC (Delaware) 100%**
- **CoalQuest Development LLC (Delaware) 100%**
- **Energy Development LLC (Iowa) 100%**

ICG Eastern Land, LLC (Delaware) 100%
ICG Natural Resources, LLC (Delaware) 100%
Mountain Gem Land LLC (West Virginia) 100%
Mountain Mining LLC (Delaware) 100%
Mountaineer Land LLC (Delaware) 100%
Otter Creek Coal, LLC (Delaware) 100%

Arch Receivable Company, LLC (Delaware) 100%

Arch Western Acquisition Corporation (Delaware) 100%
Arch Western Acquisition, LLC (Delaware) 100%
Arch Western Resources, LLC (Delaware) 99.5%
Arch of Wyoming, LLC (Delaware) 100%
Arch Western Bituminous Group, LLC (Delaware) 100%
Mountain Coal Company, L.L.C. (Delaware) 100%
Thunder Basin Coal Company, L.L.C. (Delaware) 100%
Triton Coal Company, LLC (Delaware) 100%
ACI Terminal, LLC (Delaware) 100%

Ashland Terminal, Inc. (Delaware) 100%

International Energy Group, LLC (Delaware) 100%
ICG, LLC (Delaware) 100%
Arch Coal Group, LLC (Delaware) 100%
Arch Coal Operations LLC (Delaware) 56.8%
Arch Land LLC (Delaware) 1.4%
ICG Beckley, LLC (Delaware) 100%
Arch Land LLC (Delaware) 41%
Hunter Ridge Holdings, Inc. (Delaware) 100%
Arch Coal Operations LLC (Delaware) 1%

Meadow Coal Holdings, LLC (Delaware) 100%

Prairie Holdings, Inc. (Delaware) 100%
Prairie Coal Company, LLC (Delaware) 100%

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-214373) pertaining to the Arch Coal, Inc. Omnibus Incentive Plan of our report dated February 24, 2017, with respect to the consolidated financial statements and schedule of Arch Coal, Inc. and subsidiaries included in this Annual Report (Form 10-K) for the period from October 2, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through October 1, 2016 (Predecessor).

/s/ Ernst & Young, LLP

St. Louis, Missouri
February 24, 2017

Exhibit 23.2

CONSENT OF WEIR INTERNATIONAL, INC.

We hereby consent to the reference to Weir International, Inc. in the Annual Report on Form 10-K of Arch Coal, Inc. for the year ended December 31, 2016.

We further wish to advise that Weir International, Inc. was not employed on a contingent basis and that at the time of preparation of our report, as well as at present, neither Weir International, Inc. nor any of its employees had, or now has, a substantial interest in Arch Coal, Inc. or any of its affiliates or subsidiaries.

Respectfully submitted,

By:	/s/ Dennis N. Kostic
Name:	Dennis N. Kostic
Title:	President & CEO
Date:	February 24, 2017

Exhibit 24.1

Power Of Attorney

KNOW ALL PERSONS BY THESE PRESENTS: That each of the undersigned directors and/or officers of Arch Coal, Inc., a Delaware corporation ("Arch Coal"), hereby constitutes and appoints John W. Eaves, John T. Drexler and Robert G. Jones, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power to act without the other, to sign Arch Coal's Annual Report on Form 10-K for the year ended December 31, 2016, to be filed with the Securities and Exchange Commission under the provisions of the Securities Exchange Act of 1934, as amended; to file such report and the exhibits thereto and any and all other documents in connection therewith, including without limitation, amendments thereto, with the Securities and Exchange Commission; and to do and perform any and all other acts and things requisite and necessary to be done in connection with the foregoing as fully as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

DATED: February 24, 2017

/s/ James N. Chapman	
James N. Chapman	Chairman
/s/ Patrick J. Bartels, Jr.	
Patrick J. Bartels, Jr.	Director
/s/ John W. Eaves	
John W. Eaves	Director
/s/ Sherman Edmiston, III	
Sherman Edmiston, III	Director
/s/ Patrick A. Kriegshauser	
Patrick A. Kriegshauser	Director
/s/ Richard A. Navarre	
Richard A. Navarre	Director
/s/ Scott D. Vogel	
Scott D. Vogel	Director

Exhibit 31.1

Certification

I, John W. Eaves, certify that:

1. I have reviewed this annual report on Form 10-K of Arch Coal, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(e) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(f) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ John W. Eaves

John W. Eaves
Chief Executive Officer, Director
February 24, 2017

Exhibit 31.2

Certification

I, John T. Drexler, certify that:

1. I have reviewed this annual report on Form 10-K of Arch Coal, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ John T. Drexler

John T. Drexler
Senior Vice President and Chief Financial Officer
February 24, 2017

Exhibit 32.1

Certification of Chief Executive Officer of Arch Coal, Inc. Pursuant to 18.U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

I, John W. Eaves, Chief Executive Officer of Arch Coal, Inc., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the year ended December 31, 2016 (the "Periodic Report") which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of Arch Coal, Inc.

/s/ John W. Eaves

John W. Eaves
Chief Executive Officer, Director
February 24, 2017

Exhibit 32.2

Certification of Chief Financial Officer of Arch Coal, Inc. Pursuant to 18.U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

I, John T. Drexler, Senior Vice President and Chief Financial Officer of Arch Coal, Inc., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the year ended December 31, 2016 (the "Periodic Report") which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of Arch Coal, Inc.

/s/ John T. Drexler

John T. Drexler
Senior Vice President and Chief Financial Officer
February 24, 2017

Exhibit 95

Mine Safety and Health Administration Safety Data

We believe that Arch Coal, Inc. ("Arch Coal") is one of the safest coal mining companies in the world. Safety is a core value at Arch Coal and at our subsidiary operations. We have in place a comprehensive safety program that includes extensive health & safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

The operation of our mines is subject to regulation by the Federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act). MSHA inspects our mines on a regular basis and issues various citations, orders and violations when it believes a violation has occurred under the Mine Act. We present information below regarding certain mining safety and health violations, orders and citations, issued by MSHA and related assessments and legal actions and mine-related fatalities with respect to our coal mining operations. In evaluating the above information regarding mine safety and health, investors should take into account factors such as: (i) the number of citations and orders will vary depending on the size of a coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process are often reduced in severity and amount, and are sometimes dismissed or vacated.

The table below sets forth for the twelve months ended December 31, 2016 for each active MSHA identification number of Arch Coal and its subsidiaries, the total number of: (i) violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which the operator received a citation from MSHA; (ii) orders issued under section 104(b) of the Mine Act; (iii) citations and orders for unwarrantable failure of the mine operator to comply with mandatory health or safety standards under section 104(d) of the Mine Act; (iv) flagrant violations under section 110(b)(2) of the Mine Act; (v) imminent danger orders issued under section 107(a) of the Mine Act; (vi) proposed assessments from MHSA (regardless of whether Arch Coal has challenged or appealed the assessment); (vii) mining-related fatalities; (viii) notices from MSHA of a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under section 104(e) of the Mine Act; (ix) notices from MSHA regarding the potential to have a pattern of violations as referenced in (viii) above; and (x) pending legal actions before the Federal Mine Safety and Health Review Commission (as of December 31, 2016) involving such coal or other mine, as well as the aggregate number of legal actions instituted and the aggregate number of legal actions resolved during the reporting period.

Mine or Operating Name / MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 104(d) Citations and Orders (#)	Section 110(b)(2) Violations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed (in thousands) ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern of Violations Under Section 104(e) (Yes/No)	Received Notice of Potential to Have Pattern of Violations Under Section 104(e) (Yes/No)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)	Legal Actions Pending as of Last Day of Period(1) (#)
Active Operations												
Lone Mountain Darby Fork / 15-02263	13	—	—	—	—	12.7	—	No	No	—	—	—
Lone Mountain Clover Fork / 15-18647	17	—	—	—	—	33.3	—	No	No	—	—	—
Lone Mountain Huff Creek / 15-17234	21	—	3	—	—	236.8	1	No	No	3	4	3
Lone Mountain 6C Mine / 44-06782	1	—	—	—	—	1.2	—	No	No	—	—	—
Lone Mountain Processing / 44-05898	3	—	—	—	—	0.9	—	No	No	—	—	—
Lone Mountain Days Creek / 15-17971	—	—	—	—	—	1.0	—	No	No	—	—	—
Powell Mt. Mine #1 / 15-18734	—	—	—	—	—	—	—	No	No	—	—	—
Powell Mt. Middle Splint / 44-07207	—	—	—	—	—	—	—	No	No	—	—	—
Knott County Raven Prep Plant / 15-17724	—	—	—	—	—	—	—	No	No	—	—	—
Vindex Cabin Run / 18-00133	1	—	—	—	—	0.4	—	No	No	—	—	—
Vindex Bismarck / 46-09369	1	—	—	—	—	0.4	—	No	No	—	—	—
Vindex Jackson Mt. / 18-00170	—	—	—	—	—	—	—	No	No	—	—	—
Vindex Wolf Den Run / 18-00790	—	—	—	—	—	0.4	—	No	No	—	—	—
Cumberland River Pardee Plant / 44-05014	—	—	—	—	—	—	—	No	No	—	—	—
Cumberland River Band Mill Mine / 44-06816	—	—	—	—	—	—	—	No	No	—	—	—
Cumberland River Pine Branch #1 / 44-07224	—	—	—	—	—	—	—	No	No	—	—	—
Cumberland River Trace Fork #1 / 15-19533	—	—	—	—	—	0.68	—	No	No	—	—	—

Beckley Pocahontas Mine / 46-05252	54	—	—	—	—	273.0	—	No	No	8	15	2
Beckley Pocahontas Plant / 46-09216	—	—	—	—	—	1.2	—	No	No	—	—	—
Coal Mac Holden #22 Prep Plant / 46-05909	—	—	—	—	—	0.3	—	No	No	—	—	—
Lone Mountain Processing / Mayflower Prep Plant / 44-05605	—	—	—	—	—	0.1	—	No	No	—	—	—
Coal Mac Ragland Loadout / 46-08563	—	—	—	—	—	0.1	—	No	No	—	—	—
Coal Mac Holden #22 Surface / 46-08984	2	—	—	—	—	3.0	—	No	No	—	—	—
Eastern Birch River Mine / 46-07945	—	—	—	—	—	0.2	—	No	No	—	—	—
Sentinel Mine / 46-04168	24	—	—	—	—	70.0	—	No	No	1	10	2
Sentinel Prep Plant / 46-08777	2	—	—	—	—	1.3	—	No	No	—	—	—
Mingo Logan Mountaineer II / 46-09029	53	2	—	—	1	208.3	—	No	No	10	8	5
Mingo Logan Cardinal Prep Plant / 46-09046	—	—	—	—	—	0.5	—	No	No	—	—	—
Mingo Logan Daniel Hollow / 46-09047	—	—	—	—	—	—	—	No	No	—	—	—
Leer #1 Mine / 46-09192	60	—	—	—	—	185.3	1	No	No	9	17	4
Arch of Wyoming Elk Mountain / 48-01694	—	—	—	—	—	—	—	No	No	—	—	—
Black Thunder / 48-00977	1	—	—	—	—	7.4	—	No	No	—	—	—
Coal Creek / 48-01215	3	—	—	—	—	9.6	—	No	No	1	—	1
West Elk Mine / 05-03672	20	—	—	—	—	76.7	—	No	No	—	1	—
Viper Mine / 11-02664	21	—	—	—	—	56.8	—	No	No	—	1	—
Leer #1 Prep Plant / 46-09191	2	—	—	—	—	1.0	—	No	No	—	—	—
Wolf Run Mining – Sawmill Run Prep Plant / 46-05544	—	—	—	—	—	—	—	No	No	—	—	—

(1) See table below for additional details regarding Legal Actions Pending as of December 31, 2016

Mine or Operating Name/MSHA Identification Number	Contests of Citations, Orders (as of December 31, 2016)	Contests of Proposed Penalties (as of December 31, 2016)	Complaints for Compensation (as of December 31, 2016)	Complaints of Discharge, Discrimination or Interference (as of December 31, 2016)	Applications for Temporary Relief (as of December 31, 2016)	Appeals of Judges' Decisions or Orders (as of December 31, 2016)
Lone Mountain Huff Creek / 15-17234	—	3	—	—	—	—
Beckley Pocahontas Mine / 46-05252	—	2	—	—	—	—
Sentinel Mine / 46-04168	—	1	—	—	—	—
Mingo Logan Mountaineer II / 46-09029	—	5	—	—	—	—
Leer #1 / 46-09192	—	4	—	—	—	—
Thunder Basin Coal Creek / 48-01215	—	1	—	—	—	—