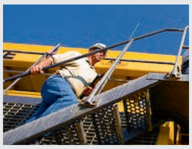
BENEATH THE SURFACE

THE COAL INDUSTRY IS GOING THROUGH A TOUGH TIME.
AS THE MARKET CYCLE TURNS AND THE INDUSTRY REBOUNDS,
COMPANIES LIKE ARCH, WITH THE RIGHT BALANCE OF ASSETS,
WILL EMERGE AS WINNERS.

ARCH COAL, INC. 2014 Annual Report

THERMAL COAL ASSETS



BLACK THUNDER
World-class mine with some of the highest-quality coal in the Powder River Basin, the largest U.S. supply region

COAL CREEK
Exceptionally low-cost mine that extends Arch's market reach into the 8400-Btu segment of the PRB market

WEST ELK
Highly productive Colorado longwall mine that produces a high-Btu, low-sulfur coal sought after around the world

VIPER
Well-positioned operation that enables Arch to compete effectively in the Illinois Basin market

COAL-MAC
Very productive Appalachian mine boasting one of the lowest cost structures in the region

ARCH HAS A DIVERSE PORTFOLIO OF LARGE, MODERN AND HIGHLY PRODUCTIVE THERMAL MINES POSITIONED IN ALL OF THE NATION'S KEY SUPPLY REGIONS. EACH OF THESE OPERATIONS IS SUPPORTED BY A HIGH-QUALITY RESERVE BASE THAT CAN SUPPORT LOW-COST, EFFICIENT MINING WELL INTO THE FUTURE, POSITIONING ARCH FOR SUCCESS AS COAL MARKETS TURN.

METALLURGICAL COAL ASSETS

BECKLEY
Cost-competitive continuous miner operation producing LV, high-quality met coal ideal for global markets

LEER
New longwall mine producing exceptionally low-cost, HVA met coal that is successfully penetrating markets

SENTINEL
Continuous miner operation producing high-quality HVA met coal for strategic U.S. and international customers

MOUNTAIN LAUREL
Longwall mine producing HVB met coal; a well-established brand in seaborne and U.S. markets

LONE MOUNTAIN
Low-cost, dual rail-served, continuous miner operation producing a highly prized PCI/met product

ARCH EXPANDED AND UPGRADED ITS COMPELLING METALLURGICAL COAL PLATFORM IN 2014 THROUGH THE RAMP-UP OF THE NEW LEER MINE. WITH THEIR COMPETITIVE COST STRUCTURES, OUR MET MINES ARE EQUIPPED TO PERFORM WELL THROUGHOUT THE MARKET CYCLE, WHILE OFFERING A DIVERSE SLATE OF HIGH-QUALITY MET PRODUCTS, ENABLING US TO SERVE A BROAD AND GLOBAL CUSTOMER BASE.

NEW COAL-FUELED GENERATION COMING ONLINE BY 2018

▲ A portion of the 150 GW of new capacity under construction from 2015-2018

Sources: Platts International and Arch Coal

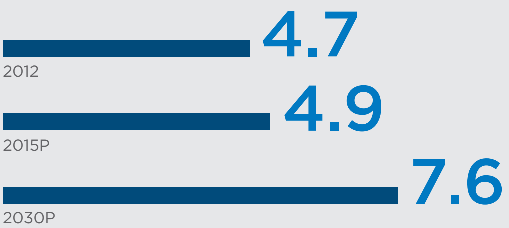
THERMAL COAL DEMAND

A total of 150 gigawatts of new coal-fueled power generation is currently under construction globally and expected to come online over the next four years. An equal amount of coal-fueled power generation is in the planning stage as worldwide electricity demand grows. In total, this new capacity should equate to over a billion tonnes of additional coal demand.

The U.S. thermal coal market is evolving due to new regulations and changing market dynamics. However, with a 40 percent fuel share, coal remains the largest source of domestic power generation and is projected to retain its leading position through at least 2030. That translates into a very sizeable market for well-positioned players like Arch. With our large, modern mines, low-cost reserves and skilled workforce, we see significant opportunities in both domestic and seaborne markets.

2.7 BILLION TONNES OF ADDITIONAL COAL IS EXPECTED TO BE CONSUMED ANNUALLY AROUND THE WORLD BY 2030 TO SUPPORT ECONOMIC DEVELOPMENT AND GROWTH.

GLOBAL THERMAL COAL CONSUMPTION
(in billions of tonnes)



Source: Wood Mackenzie

GLOBAL URBAN POPULATION
(in billions of people)

2014 **3.9**

2030P **5.0**

THE GLOBAL URBAN POPULATION IS EXPECTED TO INCREASE BY MORE THAN 1 BILLION PEOPLE BY 2030, DRIVING INFRASTRUCTURE BUILD-OUT AND INCREASED ENERGY NEEDS OVER THE NEXT 15 YEARS.

Sources: United Nations, Department of Economic and Social Affairs

METALLURGICAL COAL DEMAND

As our nation's economy expands and U.S. steel mills run at healthy utilization rates, we expect domestic demand for metallurgical coal – a key input for steel-making – to remain strong. Arch's highly competitive metallurgical platform is poised to capitalize, with its low cost structure and broad spectrum of coal qualities. Today we produce 10 percent of the country's metallurgical coal and have significant organic growth potential through our Tygart Valley reserve block, which is located near our new Leer mine.

With demand for metallurgical coal growing, supply rationalizing and new investment slowing, global metallurgical markets will correct in due course. Indeed, global steel production is projected to expand by more than 25 percent by 2030, which should spur a 45 percent increase in global met demand. With India, China and other Asian countries undergoing industrial expansion and urbanization, low-cost U.S. producers like Arch should play a sizeable and expanding role in the global metallurgical market.

GLOBAL MEGA-CITIES > 5 MILLION PEOPLE
(number of cities)

2014 **71**

2030P **104**

ROUGHLY **85** PERCENT OF THE WORLD'S 7 BILLION PEOPLE LIVE IN EMERGING ECONOMIES. THE URBANIZATION OF THESE COUNTRIES WILL STIMULATE ECONOMIC GROWTH AND SPUR GREATER STEEL CONSUMPTION.

Sources: United Nations, Department of Economic and Social Affairs

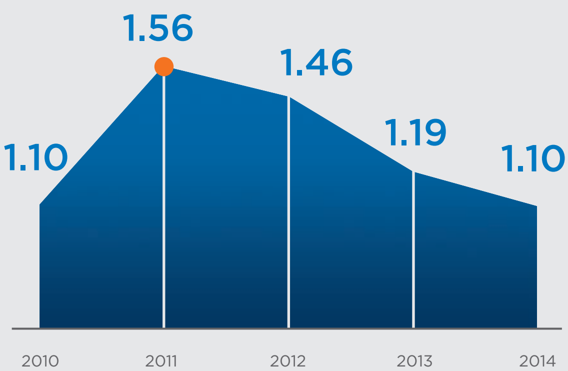
ARCH MAINTAINS A KEEN FOCUS ON SAFETY AND ENVIRONMENTAL EXCELLENCE, WHICH ARE CORE VALUES FOR OUR ORGANIZATION. OUR DEDICATION TO BEING A SAFE AND RESPONSIBLE ENERGY COMPANY IS FUNDAMENTAL TO EVERYTHING WE DO.

Please visit *responsible.archcoal.com* to learn about our world-class safety practices, water and wildlife conservation efforts, and philanthropic contributions in education – all of which play a role in strengthening the communities in which we live and work. By carrying on our traditions of operating safely and responsibly, we advance our reputation as a good corporate citizen and deliver real value to the stakeholders of Arch Coal.

SAFETY AND ENVIRONMENT

Arch's talented and dedicated workforce is our greatest asset. By embedding safety practices into our daily tasks, we continue to strive toward our ultimate goal of a perfect safety record at every operation, every year. In 2014, we continued our longstanding tradition as an industry leader in safety by achieving a total incident rate that equaled our best safety performance in history and ranked Arch first among large, diversified coal peers. In addition, our operations achieved many noteworthy milestones during the year, including surpassing three consecutive years without a lost-time incident at our Coal-Mac mine in West Virginia.

ARCH TOTAL INCIDENT RATE
(per 200,000 employee-hours worked)



ICG Acquisition in June 2011

Environmental Stewardship

Arch's commitment to environmental care is an essential part of our business. It shows through our strong environmental compliance record, our award-winning reclamation practices and our funding of clean coal technology. In 2014, Arch was honored with various awards for our environmental stewardship, including the state of Wyoming Reclamation Award, the state's top honor for reclamation excellence and wildlife habitat creation, at our Black Thunder and Coal Creek mines.

Our former mine lands are home to thriving wildlife. In 2014, the West Elk mine in Colorado completed an impressive 15 consecutive years with zero SMCRA violations.

BENEATH THE SURFACE

DEAR FELLOW SHAREHOLDERS:

The coal industry continued to face challenges in 2014. The U.S. coal sector lost roughly 40 percent of its market capitalization during the year, and international coal markets struggled with out-of-balance supply and demand fundamentals. Despite these headwinds, we are confident that we are taking the rights steps to position Arch Coal for success by staying true to our commitment to operate safely and responsibly, rightsizing the company's assets, reducing costs and preserving liquidity. As such, we remain focused on maintaining and capitalizing on the value **beneath the surface** that serves as Arch's foundation.

Over the last year, Arch successfully focused on managing the variables we can control. Although weakened coal markets and prices affected our results in 2014, we remain committed to executing our carefully crafted plan by leveraging our unique asset base and proactively adjusting our business to an evolving market landscape.

Building on Our Foundation

One value that underpins all that we do is an ongoing commitment to safety and environmental excellence. We finished 2014 with our best safety and environmental performances since 2010 – achieving an 8 percent reduction in our total incident rate and ranking first among large, diversified coal peers. We also had our second-best environmental performance in company history in 2014, improving our environmental compliance by nearly 30 percent.

Throughout 2014, Arch subsidiaries were awarded numerous safety and environmental honors, including the prestigious Sentinels of Safety award for the fourth straight year. I commend all Arch employees for their dedication to our core values and know that focus is critical to our success.

Leveraging Our Assets

In a coal market landscape that is rapidly evolving, Arch continued to streamline our operations and focus on what we do well – operating large-scale, low-cost, responsible complexes to mine and market coal.

Arch has a diverse operating platform with highly competitive mines in each of the major U.S. coal basins and a portfolio with a winning balance of metallurgical and thermal operations. This strategic combination ensures that we are positioned to capitalize on opportunities in the steel or power generation markets, while providing a measure of stability in our highly cyclical markets. Our cost-competitive metallurgical assets are among the best

FINANCIAL HIGHLIGHTS

Year Ended December 31 (in millions, except per share data)	2014	2013	2012
TONS SOLD	134.4	134.3	131.8
COAL RESERVES	5,064.4	5,278.2	5,490.0
REVENUES	$ 2,937.1	$ 3,014.4	$ 3,768.1
ADJUSTED EBITDA FROM CONTINUING OPERATIONS	$ 280.1	$ 252.1	$ 579.7
CAPITAL EXPENDITURES	$ 147.3	$ 297.0	$ 395.2
ADJUSTED DILUTED LOSS PER SHARE	$ (2.60)	$ (1.08)	$ (0.36)

Note: All figures presented exclude discontinued operations.
All non-GAAP measures are defined and reconciled at the end of this report.

in the industry and serve as a strong counterbalance to Arch's outstanding thermal assets. We achieved a significant milestone in 2014 with the successful ramp-up of our Leer mine in Appalachia. This new longwall mine has already reduced our costs in the region while improving our spectrum of metallurgical coal qualities. I'm extremely pleased with the performance of Leer in 2014 and am excited to demonstrate what it can do in the years to come. We view Leer as a keystone of our metallurgical platform, which will define Arch in Appalachia for the next decade. With the longwalls at Leer and Mountain Laurel anchoring our production and complemented by our scalable operations, including Beckley, Sentinel and Lone Mountain, we have a compelling, low-cost metallurgical profile that is capable of generating positive cashflows even during market downturns by offering a diverse range of products to both global and domestic customers.

We are also looking toward the future and have started the initial permitting and engineering process for the Tygart Valley reserve block. These reserves, which are the same reserves in which Leer currently operates, offer a uniform and contiguous high-volatile "A" metallurgical quality coal and can support several new operations, including another longwall mine. The permitting process will take time, and while we aren't investing capital in developing it now, Tygart Valley's time will come. As markets recover, this roughly 140-million-ton reserve block offers an organic growth opportunity with a high-quality, long-lived metallurgical coal brand that will be prized in the marketplace.

Our strong, competitive position in the Powder River Basin (PRB), supported by our flagship Black Thunder mine, is the centerpiece of our thermal platform and generates steady revenues. It also serves as a solid thermal base for Arch in a dynamic U.S. coal market. As new environmental regulations come into effect, we believe low-cost basins with low-emitting coals will be advantaged. The Powder River Basin has both and should excel. As a result, we expect domestic demand for PRB coal to climb over the next five years even as overall U.S. coal consumption remains flat.

Longer term, we see growing opportunities for PRB and other Western thermal coal in the expanding Pacific Rim market. West Coast port projects continue to move forward, and Millennium Bulk Terminal, in which Arch has a 38 percent equity stake, enjoys strong local support and is making measured progress.

WE ARE CONFIDENT IN OUR ABILITY TO MANAGE THROUGH THE CURRENT MARKET CYCLE AND CREATE SHAREHOLDER VALUE AS MARKETS REBOUND.

JOHN W. EAVES
President and
Chief Executive Officer
Arch Coal, Inc.

As West Coast port capacity is added, the quality of competing coals declines and the global cost curve shifts higher, we expect the Powder River Basin's role in the Pacific Rim markets to grow in importance.

Our Bituminous Thermal assets, in Colorado and the Illinois Basin, had an outstanding 2014 and captured domestic and niche international opportunities. As seaborne markets begin to rebalance over time, export-facing assets like our West Elk mine hold great potential. Our Viper operation and Knight Hawk equity interest in the Illinois Basin continue to provide steady cashflows, while our fully permitted, low-chlorine Lost Prairie reserves represent a long-term growth opportunity. We view our Bituminious Thermal segment as complementary to our Powder River Basin thermal franchise and our realigned metallurgical platform in Appalachia.

In 2014, we took additional steps to reduce our thermal coal footprint in Appalachia by selling select, non-core assets. The structural shift in Central Appalachia toward becoming a metallurgical coal basin with ancillary production of thermal coal continues, and we expect regional production to decline further in 2015. In light of this trend, we have positioned Arch's thermal profile in the East to be smaller, but more sustainable. Our remaining thermal production, primarily our Coal-Mac operation, has a strong, low-cost position that remains competitive.

Controlling All We Can

We also executed on our financial priorities in 2014, preserving liquidity, controlling costs and reducing capital spending. We lowered costs in two of our regions during the year and made progress in the third. By remaining committed to process improvement initiatives, such as a managed rebuild program that has driven down rebuild costs of underground equipment by almost 45 percent, we have improved our cost structure and the performance and lifespan of our existing fleet of machinery. We also prudently managed our capital spending without compromising our ability to efficiently run our operations or maintain our reduced cost performance. In fact, we have successfully lowered capital expenditures by nearly $250 million since 2012.

All of these actions have enabled us to preserve our liquidity and manage our cashflows during market headwinds. At the end of 2014, we had $1.2 billion of liquidity. With the steps outlined previously, our

OVER THE LAST YEAR, ARCH SUCCESSFULLY FOCUSED ON MANAGING THE VARIABLES WE CAN CONTROL. ALTHOUGH WEAKENED COAL MARKETS AND PRICES AFFECTED OUR RESULTS IN 2014, WE REMAIN COMMITTED TO EXECUTING OUR CAREFULLY CRAFTED PLAN BY LEVERAGING OUR UNIQUE ASSET BASE AND PROACTIVELY ADJUSTING OUR BUSINESS TO AN EVOLVING MARKET LANDSCAPE. — JOHN W. EAVES

levels of legacy liabilities and the absence of near-term debt maturities, we are confident in our ability to manage through the current market cycle and, more importantly, to create substantial value as coal markets rebound.

Taking the Next Steps

We expect coal demand to remain stable in the U.S. after 2015 and to grow markedly abroad as the world population increases, industrialization continues and urbanization advances. In order to achieve their economic objectives, nations around the world will need more power and more steel – and that means more coal. Global energy needs are expected to grow almost 20 percent over the next decade, and coal is projected to be a baseline fuel essential to meeting that demand cost-effectively.

While recent and pending environmental regulations will reduce the size of the U.S. coal-based power generation fleet over the next five years, we are confident coal will remain a cornerstone of U.S. power demand for decades to come. Generators are taking steps to retrofit their largest and most efficient plants – plants that should run harder and more often in the years ahead. Meanwhile, we will continue to engage in the policy debate in Washington D.C., and elsewhere, championing coal's essential role in preserving a reliable, secure and affordable power generation system for all Americans. Overall, we expect the U.S. will remain a very sizeable coal market – providing opportunities for well-positioned companies like ours.

As we look ahead in a still-challenging coal market environment, I feel good about where we stand. We expect to build upon what we have achieved so far and will continue to execute on the plans we have strategically crafted. By leveraging our exceptional asset base, proactively managing our cashflows, delivering stronger financial results and relying on our exceptional workforce, we will endure current market headwinds and emerge as an even stronger competitor ready to capitalize on an improving market environment.

John W. Eaves

John W. Eaves
President and CEO
March 1, 2015

ArchCoal™

Annual Report On Form 10-K
For the Year Ended December 31, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549
Form 10-K

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

For the fiscal year ended December 31, 2014

or

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

Commission file number: 1-13105

Arch Coal, Inc.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ 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, 2014 was approximately $771.8 million.

At February 13, 2015 there were 212,274,662 shares of the registrant's common stock outstanding.

Portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission in connection with the 2015 annual stockholders' meeting to be held on April 23, 2015 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

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 35 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:

- 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 credit facility and other financing arrangements;
- 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; 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 law.

PART I

Item 1. BUSINESS

Introduction

We are one of the world's largest coal producers. For the year ended December 31, 2014, we sold approximately 134 million tons of coal, including approximately 1.3 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, 2014, we operated, or contracted out the operation of, 16 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.

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.

Coal Characteristics

End users generally characterize coal as steam 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 traded globally and can be transported to demand centers by ship, rail, barge or truck. World coal production totaled 7.8 billion tonnes in 2013 (the latest full year data currently available) according to the International Energy Agency (IEA) and the World Coal Association. Total hard coal production totaled 7.0 billion tonnes in 2013, while global production of brown coal totaled 840 million tonnes. Also according to IEA estimates, China remained the largest producer of coal in the world, producing over 3.5 billion tonnes in 2013. The United States and India follow China with hard coal production of over 900 million tonnes and 600 million tonnes, respectively, in 2013.

Cross-border coal trade of hard coal was close to 1.3 billion tonnes in 2013 according to the IEA. China was the largest importer of globally traded coal in 2013, taking over 327 million tonnes of hard coal, although preliminary estimates indicate that Chinese imports declined in 2014. Japan imported more than 195 million tonnes in 2013, followed by India with nearly 180 million tonnes. OECD Europe imported 253 million tonnes.

Among the nations principally supplying coal to the global power and steel markets are Australia and Indonesia, as well as Russia, the United States, Colombia and South Africa. Australia has significant reserves and infrastructure, and is also benefiting from the current weakness in the Australian dollar. Indonesia continues to exhibit substantial growth in its coal exports; however, its growing domestic energy demand, together with governmental attempts to limit exports, may result in a slowing of growth or even a decrease in exports over time. Increasing calls to bolster domestic power supply, together with pressure to improve wages for miners, may also limit South African exports in the future.

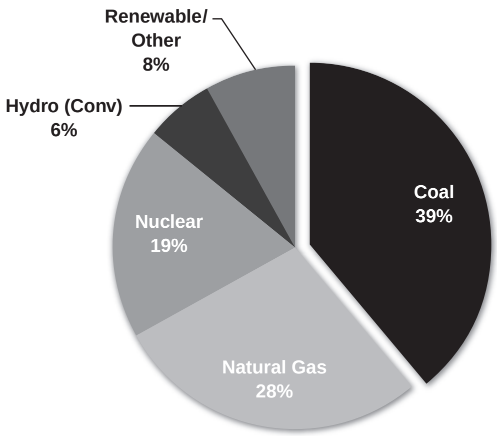
Global Coal Supply and Demand. The supply and demand fundamentals in global coal markets remained challenged in 2014. Although coal was cost-competitive with natural gas in 2014, Europe's weak economic growth resulted in only modest changes in import coal demand. Additionally, economic uncertainty lowered demand for imported finished goods, which led to reduced steel consumption and therefore lower demand for metallurgical coal. In China, a slowing economy along with abundant hydropower generation has resulted in a modest decline in coal imports in 2014 according to preliminary reports. China continues to add coal-based power generation capacity, but slower economic growth and new regulations on emissions around large urban centers could lead to more moderate rates of growth in the future, albeit on a large base.

Despite near-term cyclical challenges, coal is expected to remain the dominant fuel for electric power generation worldwide. According to the IEA, coal is projected to fuel over 33% of the world's electric power through 2040. Most of the growth in coal consumption is expected to occur in Asia, with China and India as the largest consumers going forward. In the metallurgical markets, we expect some additional supply rationalization to occur over the next 12 to 24 months; however, fundamental demand for metallurgical coal is expected to remain strong. Again, Asia is expected to be the center for most of the global demand growth for metallurgical coal. China, India, Japan and South Korea are all expected to increase steel production during the next five years.

U.S. Coal Consumption. In the United States, coal is used primarily by power plants to generate electricity, by steel companies to produce coke for use in blast furnaces, and by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing or processing facilities. Although final data is not yet available, coal consumption in the United States is estimated to be approximately 920 million tons in 2014, according to the Energy Information Administration's (EIA) Short Term Energy Outlook. Coal consumption decreased in 2014 by 0.7%, or around 5 million tons as compared to 2013.

According to the EIA, coal accounted for approximately 39% of U.S. electricity generation from January through November 2014. This is roughly equivalent to the same period in 2013 but approximately 2 percentage points higher than the full-year 2012. Overall, power generation was up 1.2% based on the first 11 months of the year. Inventories of coal at power generation facilities ended the year at 139 million tons, according to EIA's Short Term Energy Outlook. This is about 9 million tons, or 6% lower, than the end of 2013.

The following chart shows the breakdown of U.S. electricity generation by energy source for January through November 2014, according to the EIA:



Source: EIA Electric Power Monthly (January 2015).

The following chart shows historical and projected demand trends for U.S. coal by consuming sector for the periods indicated, according to the EIA:

Sector	Actual 2009	Estimated 2014	Forecast 2015	Forecast 2020	Forecast 2040	Annual Growth 2012 - 2040
	(Tons, in millions)					
Electric power	934	854	841	892	909	0.3%
Other industrial	45	43	41	49	50	0.5%
Coke plants	15	21	21	22	18	(0.5)%
Residential/commercial	3	2	2	2	2	(0.1)%
*Total U.S. coal consumption	997	920	905	965	979	0.3%

Source: EIA Annual Energy Outlook 2014
EIA Short Term Energy Outlook (February 2015)
EIA Monthly Energy Review (January 2015)

* Columns may not total due to rounding.

Historically, coal has been considerably less expensive than natural gas or oil. However, the growth of hydraulic fracturing (fracking) combined with the current inability to transport U.S. produced natural gas beyond North America has resulted in an oversupply. New export facilities for natural gas are under construction, and this is expected to reduce U.S. over-supply over the next five years. Until then, periods of market imbalance could affect coal both positively and negatively. At the beginning of 2014, a period of below normal temperatures drove consumption of natural gas for heating purposes to record levels and tested the supply of the fuel. Since then, both mild temperatures and record high natural gas production have moved the market from undersupply to oversupply, and this has reduced natural gas prices at the beginning of 2015.

U.S. Coal Production. The United States is the second largest coal producer in the world, exceeded only by China. According to the EIA, there are over 200 billion 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 MSHA, U.S. coal production increased an estimated 12 million tons in 2014, to 997 million tons.

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

The Western region includes the Powder River Basin and the Western Bituminous region. According to the EIA, coal produced in the western United States increased from an estimated 530 million tons in 2013 to 539 million tons in 2014. 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 exists in greater abundance and is easier to mine and, 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.

The Appalachia region is further divided into north, central and southern regions. According to the EIA, amounts of coal produced in the Appalachian region remained consistent at close to 270 million tons in 2013 and 2014. Central Appalachia is further disadvantaged for power generation because of the depletion of economically attractive reserves, permitting issues, and increasing costs of production. Central Appalachia includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. 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 increased from 183 million tons in 2013 to approximately 187 million tons in 2014. 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.

U.S. Coal Exports and Imports. Coal exports declined approximately 20 million tons to 98 million tons in 2014. The decline in 2014 was primarily caused by growing global coal supply along with slowing demand growth which displaced some of the volume originating in the United States. Additionally, unfavorable foreign currency exchange disadvantaged some United States coal in certain markets. The seaborne market is cyclical, but the IEA projects the seaborne coal trade to grow to 1.2 billion tonnes by 2020 in their *New Policies Scenario*, an increase of 165 million tons. The United States is expected to continue its role as a major supplier to the global market. Interest in access to the coal markets overseas by domestic producers, along with increased international consumer interest in United States coal, continues to fuel considerable interest in developing new port capacity, particularly on the West Coast.

Historically, coal imported from abroad has represented a relatively small share of total domestic coal consumption, and this remained the case in 2014. Imports reached close to 36 million tons in 2007, but have fallen since then. According to the EIA, coal imports were 11.3 million tons in 2014. The decline is mostly attributable to more competitive pricing for domestic coal and stronger demand from international markets for seaborne coal. The majority of the coal imported into the United States originates from Colombia.

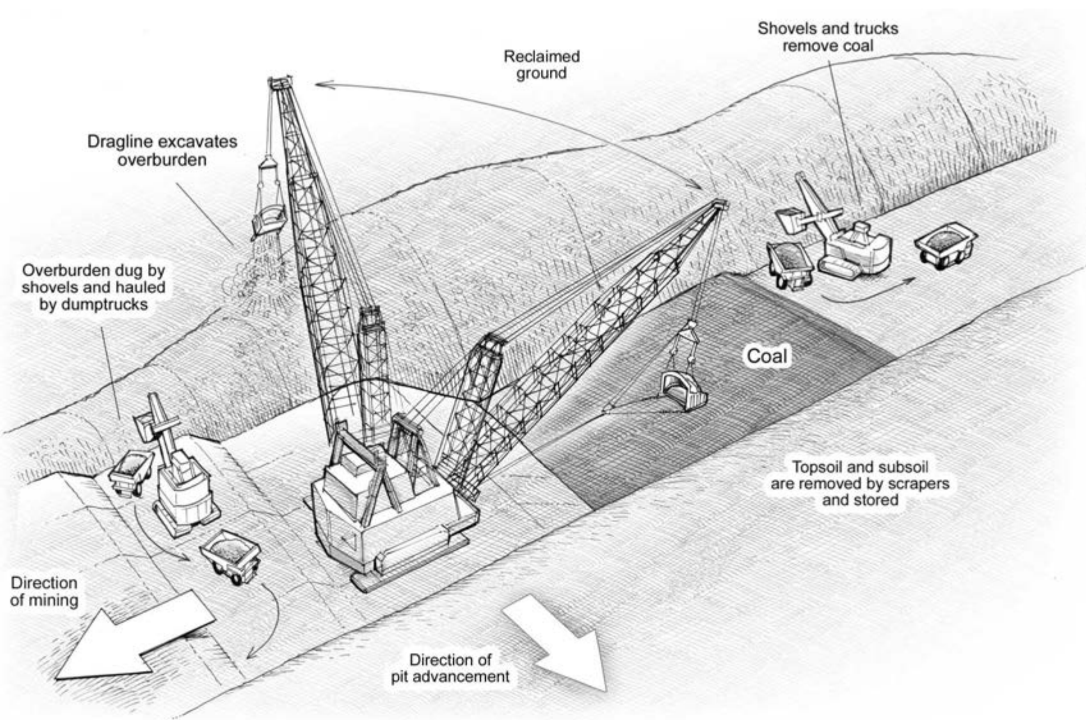
Coal Mining Methods

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.

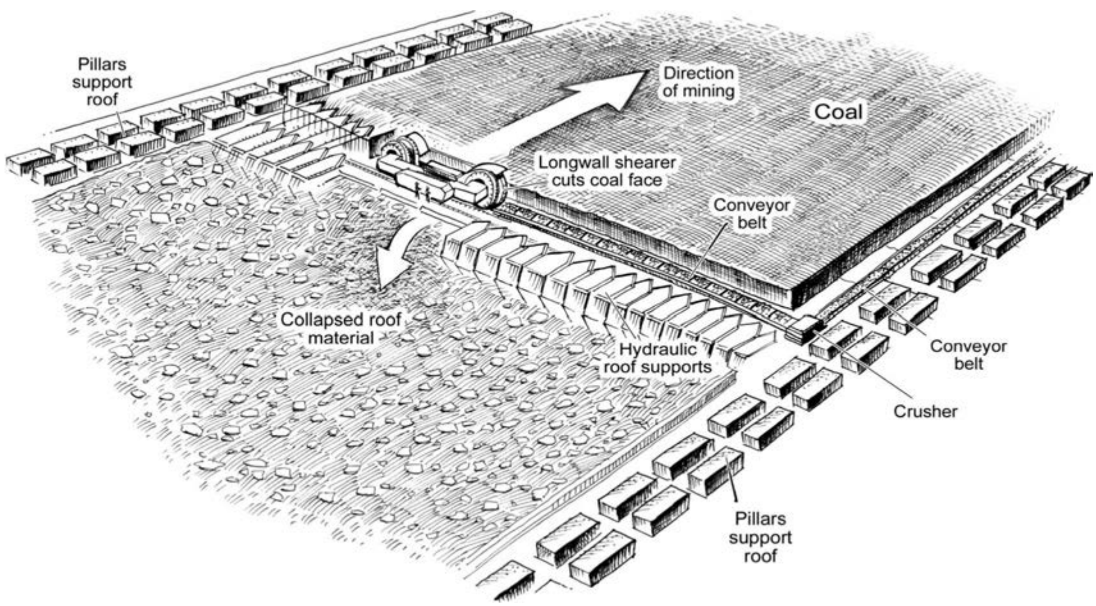
The following diagram illustrates a typical dragline surface mining operation:



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."

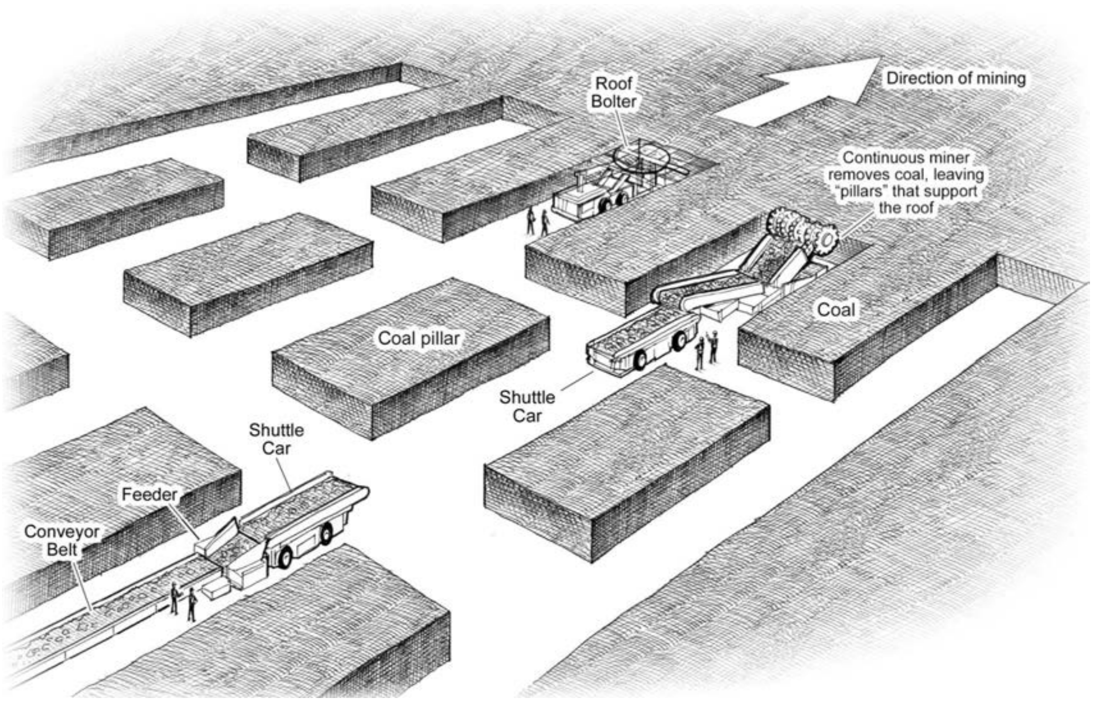
Our underground mines are typically operated using one or both of two different mining techniques: longwall mining and room-and-pillar mining.

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.

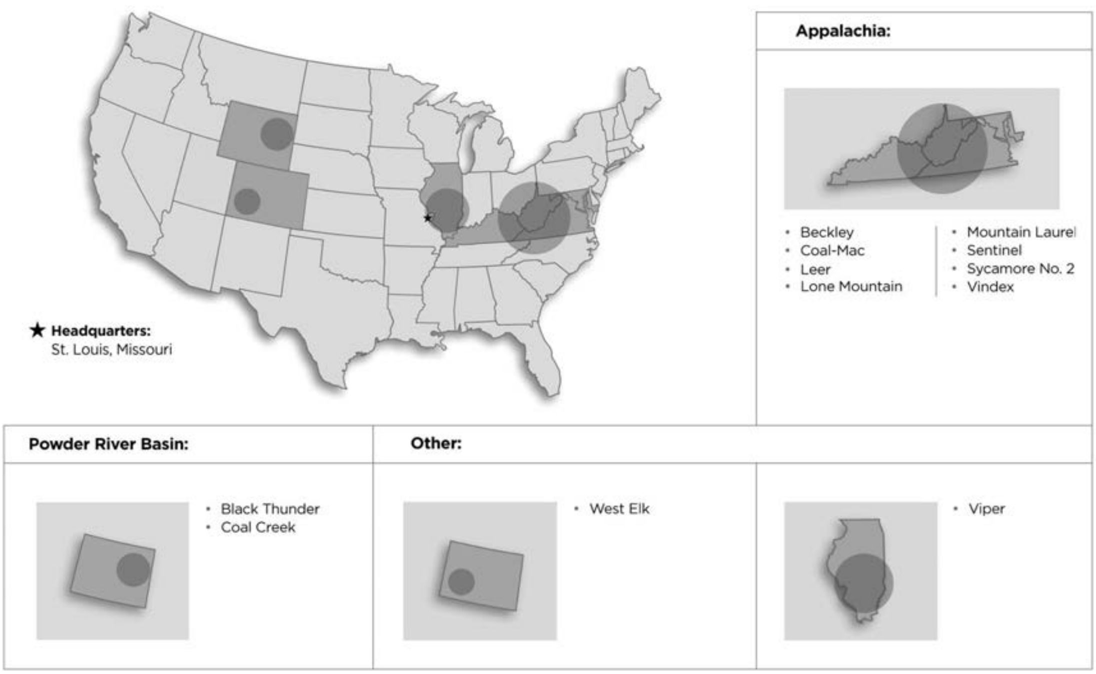
For more information about the locations of our preparation plants, you should see the section entitled ''Our Mining Operations'' below.

Our Mining Operations

General. At December 31, 2014, we operated, or contracted out the operation of, 16 active mines in the United States. Our reportable segments are based on the major coal producing basins in which we operate. Our reportable segments are the Powder River Basin segment, with operations in Wyoming; and the Appalachia segment, with operations in West Virginia, Kentucky, Maryland and Virginia. We also sell coal from operations in Colorado and Illinois. Geology, coal transportation routes to consumers, regulatory environments and coal quality can vary from segment to segment. We incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2014, 2013, and 2012 contained in Note 26 beginning on page F-50.

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 map shows the locations of our active mining operations:



The following table provides a summary of information regarding our active mining complexes as of December 31, 2014, including the total sales associated with these complexes for the years ended December 30, 2012, 2013, and 2014 and the total reserves associated with these complexes at December 31, 2014. The amount disclosed below for the total cost of property, plant and equipment of each mining complex does not include the costs of the coal reserves that we have assigned to an individual complex.

Mining Complex	Captive Mines[1]	Contract Mines[1]	Mining Equipment	Railroad	Tons Sold[2][3] 2012	2013	2014	Total Cost of Property, Plant and Equipment at December 31, 2014	Assigned Reserves
					(Million tons)			($ millions)	(Million tons)
Powder River Basin:									
Black Thunder	S	—	D, S	UP/BN	92.9	100.7	101.2	$1,205.5	1,262.6
Coal Creek	S	—	D, S	UP/BN	7.5	8.5	9.4	147.8	160.8
Other:									
West Elk	U	—	LW, CM	UP	6.7	6.1	6.5	413.6	65.2
Viper	U	—	CM	—	2.1	2.2	2.2	93.0	33.0
Appalachia:									
Coal-Mac	S	—	L, E	NS/CSX	3.3	3.1	2.8	203.4	26.4
Lone Mountain	U(3)	—	CM	NS/CSX	2.0	2.0	1.9	260.0	18.2
Mountain Laurel	U	S(2)	L, LW, CM	CSX	3.7	2.9	2.6	526.4	47.9
Beckley	U	—	CM	CSX	1.1	1.1	1.0	108.8	29.9
Vindex	S	—	L, E	CSX	1.0	0.6	0.5	88.6	12.8
Sycamore No. 2	—	U	CM	—	0.4	0.4	0.5	16.0	7.1
Sentinel	U	—	CM	CSX	1.2	1.0	1.1	71.5	11.3
Leer	U	—	CM, LW	CSX	—	—	2.7	440.0	42.0
Totals					121.9	128.6	132.4	$3,574.6	1,717.2

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 and contract mines, if more than one, at the mining complex as of December 31, 2014. Captive mines are mines that we own and operate on land owned or leased by us. Contract mines are mines that other operators mine for us under contracts 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) 2012 tons sold numbers do not include tons of coal sold from the following mining complexes that were closed or idled during the 2012 calendar year: Arch of Wyoming, East Kentucky, Eastern, Flint Ridge, Imperial, Knott County/Raven and Patriot. We sold 2.2 million tons of coal from these mining complexes in 2012. 2012 and 2013 tons sold numbers do not include tons of coal sold from the following mining complexes that were sold in the 2013 calendar year: Dugout Canyon, Skyline and Sufco. We sold 8.9 million and 5.3 million tons of coal from these mining complexes in 2012 and 2013, respectively. 2012, 2013 and 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 3.5 million, 2.7 million and 0.8 million tons of coal from these two mining complexes in 2012, 2013 and 2014, respectively.

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 steam 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 1.3 billion tons of proven and probable reserves at December 31, 2014. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of 190 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2020 before annual output starts to significantly decline, although in practice production would drop in phases extending the ultimate mine life. 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 six 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 steam 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 160.8 million tons of proven and probable reserves at December 31, 2014. The air quality permit for the Coal Creek mine allows for the mining of coal at a rate of 50 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2025 before annual output starts to significantly decline.

The Coal Creek complex currently consists of two 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.

Appalachia

Coal-Mac. Coal-Mac is a surface mining complex located on approximately 46,900 acres in Logan and Mingo Counties, West Virginia. Surface mining operations at the Coal-Mac mining complex extract steam 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 26.4 million tons of proven and probable reserves at December 31, 2014. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021 before annual output starts to significantly decline.

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.

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 steam and metallurgical 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 18.2 million tons of proven and probable reserves at December 31, 2014. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2025 before annual output starts to significantly decline.

The complex currently consists of three underground mines operating a total of seven 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 steam and metallurgical coal from the Cedar Grove and Alma seams. Surface mining operations at the Mountain Laurel mining complex extract coal from a number of different splits of the Five Block, Stockton and Coalburg seams.

We control a significant portion of the coal reserves through outright ownership and private leases. The Mountain Laurel mining complex had approximately 47.9 million tons of proven and probable reserves at December 31, 2014. The longwall mine is expected to operate through at least 2020 and potentially longer. In addition, the existing reserve base should support continuous miner operations beyond that date.

The complex currently consists of one underground mine operating a longwall and a total of four continuous miner sections, two contract surface operations, 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 25,300 acres in Raleigh County, West Virginia. Beckley is extracting high quality, low-volatile metallurgical coal in the Pocahontas No. 3 seam.

A significant portion of the coal reserves are controlled through private leases. As of December 31, 2014, we had approximately 29.9 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2030. 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.

Vindex. The Vindex mining complex consists of a surface mine located on approximately 40,300 acres in Maryland and West Virginia. Mining operations extract coal from the Upper Freeport, Middle Kittanning, Pittsburgh, Little Pittsburgh and Redstone seams. Coal is sold on a raw basis and trucked directly to the customer.

We control all of the coal reserves through private leases. As of December 31, 2014, we had approximately 12.8 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until at least 2021.

Sycamore No. 2. The Sycamore No. 2 mining complex is an active underground mine operated by a contract miner located on approximately 8,800 acres in Harrison County, West Virginia. Mining operations extract coal from the Pittsburgh seam. The coal produced by this mining complex is sold on a raw basis and is transported to current customers by truck.

As of December 31, 2014, the Sycamore No. 2 mining complex had approximately 7.1 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2028.

Sentinel. The Sentinel mining complex consists of one underground mine, a preparation plant and a loadout facility located on approximately 25,200 acres in Barbour County, West Virginia. Mining operations currently extract 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.

We control a significant portion of the Clarion seam coal reserves through private leases. As of December 31, 2014, we had approximately 11.3 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021.

Leer. The Leer Complex, located in Taylor County, West Virginia, includes approximately 42.0 million tons of coal reserves as of December 31, 2014 and has both steam and metallurgical quality coal in the Lower Kittanning seam, and is part of approximately 78,500 acres that is considered our Tygart Valley area. Substantially all of the reserves at Leer are owned rather than leased from third parties.

The Leer Complex is designed to have 3.5 million tons of capacity per year of high quality coal that is well suited to both the high volatile metallurgical and utility markets. 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. Without the addition of more coal reserves, the current reserves could sustain the longwall mine at current production levels until about 2024 and support continuous miner production until 2030.

Other

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 steam 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 65.2 million tons of proven and probable reserves at December 31, 2014. Without the addition of more coal reserves, the current reserves could sustain current production levels through 2024 before annual output starts to significantly decline.

The West Elk complex currently consists of a longwall, two 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 48,200 acres in central Illinois near the city of Springfield. Mining operations extract steam 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, 2014, we had approximately 33.0 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2026.

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 carbon 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 certain 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 smaller groups of sales personnel in our Singapore, Beijing and London offices. In addition to selling coal produced in 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 steam and metallurgical coal to domestic and foreign utilities, steel producers and other industrial facilities. For the year ended December 31, 2014, we derived approximately 15% of our total coal revenues from sales to our three largest customers U.S. Steel, Southern Company, and Tennessee Valley Authority—and approximately 38% of our total coal revenues from sales to our 10 largest customers.

In 2014, we sold coal to domestic customers located in 36 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 2014 we also exported coal to Europe, Asia, North America (outside the United States) and South America. Exports to foreign countries were $0.6 billion, $0.8 billion and $1.2 billion for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014 and 2013, trade receivables related to metallurgical-quality coal sales totaled $76.0 million and $70.5 million, respectively, or 36% of total trade receivables. 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, 2014, were as follows:

(In thousands)	
Europe	$277,565
Asia	156,057
North America	78,445
Central and South America	20,496
Brokered Sales	79,354
Total	$611,917

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 2014, we sold approximately 60% of our coal under long-term supply arrangements. The majority of our supply contracts include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our long-term supply agreements may include a variable pricing system. While most of our sales contracts are for terms of one to five years, some are as short as one month and other contracts have terms exceeding five years. At December 31, 2014, the average volume-weighted remaining term of our long-term contracts was approximately 2.44 years, with remaining terms ranging from one to 6 years. At December 31, 2014, remaining tons under long-term supply agreements, including those subject to price re-opener or extension provisions, were approximately 189 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 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 the section entitled ''Quantitative and Qualitative Disclosures About Market Risk'' for more information about the market risks associated with these strategies at December 31, 2014.

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 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 the export terminal, and we are usually responsible for the cost of transporting coal to the export terminals. In some cases we may enter into long-term throughput agreements with export terminals that contain minimum throughput obligations. In the event we do not meet those minimum thresholds, we may be obligated to pay liquidated damage amounts to such terminals. We transport our coal to Atlantic or Pacific coast 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 22% 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 serves international customers, as well as domestic coal users located along the Atlantic coast of the United States.

We also own a 38% interest in Millennium Bulk Terminals—Longview, LLC (MBT), the owner of a bulk commodity terminal on the Columbia River near Longview, Washington. MBT is currently working to obtain the required approvals and necessary permits to complete upgrades to enable coal shipments through the brownfield terminal.

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 Alpha Natural Resources, Inc., Cloud Peak Energy, CONSOL Energy Inc., Patriot Coal Corporation, Peabody Energy Corp. and Walter Energy, Inc. Some of these coal producers are larger than we are and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in each of the geographic regions in which we operate, as well as companies that produce coal from one or more foreign countries, such as Australia, Colombia, Indonesia and South Africa.

Additionally, coal competes with other fuels, such as natural gas, nuclear energy, hydropower, wind, solar and petroleum, for steam and electrical power generation. Costs and other factors relating to these alternative fuels, such as safety and environmental considerations, 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 ''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. While it is not possible to accurately quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs 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 reinstate the previous version of the rule, but do not announce a new interpretation of the rule regarding the ability to construct excess spoil fills. We cannot predict how the regulations will be applied or how they may affect coal production, though there are reports that any reinterpretation of the prior version of the rule would be to restrict the ability to construct mining related structures in streams. Such an interpretation could curtail surface mining operations in and near streams-especially in central Appalachia.

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 2014, we recorded $34.2 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 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 order to address some of these uncertainties, we use self-bonding to secure performance of certain obligations in Wyoming. As of December 31, 2014, we have self-bonded an aggregate of approximately $458.5 million, posted an aggregate of approximately $177.7 million in surety bonds for reclamation purposes and secured $3.5 million in letters of credit for reclamation bonding obligations. In addition, we had approximately $138.1 million of surety bonds and letters of credit outstanding at December 31, 2014 to secure workers' compensation, coal lease and other obligations.

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. In reaction to recent mine accidents, federal and state legislatures and regulatory authorities have increased scrutiny of mine safety matters and passed more stringent laws governing mining. For example, in 2006, Congress enacted the MINER Act. The MINER Act imposes additional obligations on coal operators including, among other things, the following:

- development of new emergency response plans that address post-accident communications, tracking of miners, breathable air, lifelines, training and communication with local emergency response personnel;
- establishment of additional requirements for mine rescue teams;
- notification of federal authorities in the event of certain events;
- increased penalties for violations of the applicable federal laws and regulations; and
- requirement that standards be implemented regarding the manner in which closed areas of underground mines are sealed.

In 2008, the U.S. House of Representatives approved additional federal legislation which would have required new regulations on a variety of mine safety issues such as underground refuges, mine ventilation and communication systems. Although the U.S. Senate failed to pass that legislation, it is possible that similar legislation may be proposed in the future. Various states, including West Virginia, have also enacted laws to address many of the same subjects. The costs of implementing these safety and health regulations at the federal and state level have been, and will continue to be, substantial. In addition to the cost of implementation, there are increased penalties for violations which may also be substantial. Expanded enforcement has resulted in a proliferation of litigation regarding citations and orders issued as a result of the regulations.

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 2014, we recorded $70.3 million of expense related to this excise tax.

Clean Air Act. The federal Clean Air Act and similar state and local laws that regulate air emissions affect coal mining directly and indirectly. Direct impacts on coal mining and processing operations include Clean Air Act permitting requirements and emissions control requirements relating to particulate matter which may include controlling fugitive dust. The Clean Air Act also indirectly affects coal mining operations 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, regulation of additional emissions, such as greenhouse gases, has been announced by the U.S. Environmental Protection Agency, which we refer to as EPA, and those regulations will likely apply to new and existing coal-fueled power plants. Other greenhouse gas regulations apply to industrial boilers (see discussion of Climate Change, below) and this application 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. Once the EPA finalizes those designations, individual states must 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 will affect many power plants, especially coal-fueled power plants, and all plants in non-attainment areas.

- *Ozone.* On November 25, 2014, the EPA released a proposed rule that would revise the existing NAAQS for ozone. EPA must finalize this new standard by October 1, 2015. The proposed NAAQS revisions would significantly reduce both the primary and secondary ozone standards from their current level of 75 ppb as an 8-hour average to a level between 65 and 70 ppb. The EPA will also accept public comment on retaining the current standard of 75 ppb or lowering the standard to 60 ppb. Significant additional emission control expenditures will likely be required at certain coal-fueled power plants to meet the new 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.

- *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.

- *Clean Air Interstate Rule.* 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 pursuant to a cap and trade program similar to the system now in effect for acid deposition control and to that proposed by the Clean Skies Initiative.

  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) and received thousands of comments on the proposal. 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 may affect the market for coal inasmuch as multiple existing coal fired units are 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. CSAPR Phase 1 implementation is now scheduled for 2015, with Phase 2 beginning in 2017. 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.

- *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) 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. 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. The result of the EGU MATS and state mercury and air toxics controls is that these rules may adversely affect the demand for coal.

- *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*) 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, but we are unable to predict the magnitude of the impact.

Climate Change. One by-product of burning coal is carbon dioxide, which is considered a greenhouse gas and is a source of concern with respect to global warming. On June 2, 2014, the EPA proposed a sweeping rule to cut carbon emissions from existing electric generating units, including coal-fired power plants. The proposed rule (79 FR 34829), known as the ''Clean Power Plan,'' would require existing power plants to reduce their carbon dioxide emissions 30% from 2005 levels by the year 2030. The proposed 30% reduction rate represents a nationwide target; there are then state-by-state mandatory targets and interim benchmarks to achieve, based on several state-specific criteria. The EPA gave each state its own emission reduction target and interim benchmark to achieve based on its emissions levels from 2012. The EPA retains the authority to take over a state's program if the state fails to achieve its targets. The EPA received public comments on the proposed rule through December 1, 2014, and plans to finalize the proposed rule by summer 2015. The Clean Power Plan has been the subject of many lawsuits, challenging, among other things, the EPA's power to promulgate the rule. If the Clean Power Plan is passed as proposed, and withstands legal challenges, it is projected to have an adverse impact on the demand for coal nationally. Some studies estimate that the Clean Power Plan will reduce coal generation in the U.S. by 25%.

Future regulation of greenhouse gases in the United States could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes under the Clean Air Act, federal or state adoption of a greenhouse gas regulatory scheme, or otherwise. The U.S. Congress has considered various proposals to reduce greenhouse gas emissions, but to date, none have become law. In April 2007, the U.S. Supreme Court rendered its decision in *Massachusetts v. EPA*, finding 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. On December 15, 2009, the EPA published a formal determination that six greenhouse gases, including carbon dioxide and methane, endanger both the public health and welfare of current and future generations. In the same Federal Register rulemaking, the EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. Although *Massachusetts v. EPA* did not involve the EPA's authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the EPA has since determined that it has the authority to regulate greenhouse gas emissions from power plants. In January 2014, EPA proposed performance standards for emissions of carbon dioxide from new fossil-fuel fired power plants. The draft rule proposes a separate standard of performance for coal-fired plants based on partial implementation of carbon capture and storage as the best system of emission reduction. The rule, if finalized and upheld in court, is expected to curtail the construction of new coal-fired power plants. In addition, once a standard for new plants is established, the EPA is required to propose rules imposing performance standards related to carbon dioxide emissions on existing power plants. These rules have not yet been proposed, but if finalized and upheld in court could further curtail the use of coal in power plants.

In addition to the federal regulation, many states and regions have adopted greenhouse gas initiatives. These state and regional climate change rules may 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 regime, if implemented by the states in which our customers operate or at the federal level, will not affect the future market for coal in those regions. Increased efforts to control greenhouse gas emissions could result in reduced 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. In 2012, the federal district court for the Southern District of West Virginia granted summary judgment to citizens in one such suit alleging violations of the water quality standard for selenium. In 2014, the same court found in another such suit that discharges of conductivity from two West Virginia mines were causing violations of West Virginia's narrative water quality standards. Both cases were resolved prior to any appeal and it is difficult to predict whether such suits will continue to be successful.

Citizens may also sue under the Clean Water Act when pollutants are being discharged without NPDES permits. Beginning in 2013, multiple citizen 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 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. Currently, certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management. In addition, Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In its 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion products generated at electric utility and independent power producing facilities, such as coal ash, and left the exemption in place. In May 2000, the EPA concluded that coal combustion products do not warrant regulation as hazardous waste under RCRA and again retained the hazardous waste exemption for these wastes. The EPA also determined that national non-hazardous waste regulations under RCRA Subtitle D are needed for coal combustion products disposed in surface impoundments and landfills and used as mine-fill. In March of 2007 the Office of Surface Mining and the EPA proposed regulations regarding the management of coal combustion products. The EPA concluded that beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. As long as this exemption remains in effect, it is not anticipated that regulation of coal combustion waste will have any material effect on the amount of coal used by electricity generators. A final rule has not been promulgated. Most state hazardous waste laws also exempt coal combustion products, and instead treat it as either a solid waste or a special waste. Any costs associated with handling or disposal of hazardous wastes would increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, contamination caused by the past disposal of ash can lead to material liability. 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, 2014, we employed approximately 5,000 full and part-time employees, six of whom are represented by the Scotia Employees Association. We believe that our relations with all employees are good.

Executive Officers

The following is a list of our executive officers, their ages as of February 27, 2015 and their positions and offices during the last five years:

Name	Age	Position
Kenneth D. Cochran	54	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 Millennium Bulk Terminals-Longview, LLC, Knight Hawk Holdings, LLC, and Tongue River Holding Company.
John T. Drexler	45	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	57	Mr. Eaves currently serves as our President and Chief Executive Officer. Mr. Eaves served as our President and Chief Operating Officer from 2006 until he was appointed as Chief Executive Officer in April 2012. From 2002 to 2006, Mr. Eaves served as our Executive Vice President and Chief Operating Officer. Mr. Eaves is currently a director of Arch Coal, Inc. and the chairman of the National Coal Council, and also serves on the board of COALOGIX, National Mining Association, the Business Roundtable, the American Coalition for Clean Coal Electricity and the Business Council, and he was previously a director of Advanced Emissions Solutions, Inc.
Robert G. Jones	58	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	54	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.

Name	Age	Position
Paul A. Lang	54	Mr. Lang 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 Arch Coal, Inc., 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 chairman of the University of Wyoming's School of Energy Resources Council.
Deck S. Slone	51	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 a director of Millennium Bulk Terminals—Longview and DKRW Advanced Fuels. In addition, Mr. Slone serves as co-chair of the Coal Utilization Research Council, as a director and member of the executive committee of the World Coal Association, as a director of the American Coal Foundation and as a member of the steering committee of the Consortium for Clean Coal Utilization at Washington University in St. Louis.
John A. Ziegler, Jr.	48	Mr. Ziegler was appointed Chief Commercial Officer in March 2014. Mr. Ziegler served as our 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 of Arch Coal Sales Company, as well as other senior management positions at Arch Coal Sales Company. 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. 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 Our Operations

Coal prices are subject to change based on a number of factors and coal prices are currently depressed. If coal prices remain depressed, or if there is a substantial or extended 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 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;
- 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; and
- market price fluctuations for sulfur dioxide emission allowances.

Coal prices are currently depressed based on a number of factors outside our control. If coal prices remain depressed, or if there is a substantial or extended decline in the prices we receive for our future coal sales contracts, it could materially and adversely affect us by decreasing our profitability and the value of our coal reserves.

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;
- unexpected or accidental surface subsidence from underground mining;
- accidental mine water discharges, fires, explosions or similar mining accidents;
- delays 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 75% of the coal volume we sold in 2014, 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.

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, could materially reduce coal prices and therefore materially reduce our revenues and profitability. 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.

In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas. A decline in the price of natural gas, or sustained low natural gas prices, could cause demand for coal to decrease and adversely affect the price of our coal. Sustained periods of low natural gas prices may also cause utilities to phase out or close existing coal-fired power plants or reduce construction of any new coal-fired power plants, which could have a material adverse effect on demand and prices for our coal.

Unfavorable economic and market conditions could adversely affect our revenues and profitability.

Global economic downturns have had and in the future could have a negative impact on both the coal industry and on various customers. 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. 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.

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 the majority of our coal sales during 2014. 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. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. 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 generators. In addition, state and federal mandates for increased use of electricity from renewable energy sources could 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.

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 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. 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, and 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. 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.

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; 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.

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. 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 ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

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 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 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 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, 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.

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.

We sell a portion of our coal under long-term coal supply agreements, which we define as contracts with terms greater than one year. Under these arrangements, we fix the prices of coal shipped during the initial year and may adjust the prices in later years. As a result, at any given time the market prices for similar-quality coal may exceed the prices for coal shipped under these arrangements. 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.

Because we sell a portion of our coal production under long-term coal supply agreements, our ability to capitalize on more favorable market prices may be limited. Conversely, at any given time we are subject to fluctuations in market prices for the quantities of coal that we have produced or plan to produce but which we have not committed to sell. As described above under ''A substantial or extended decline in coal prices could negatively affect our profitability and the value of our coal reserves,'' the market prices for coal may be volatile and may depend upon factors beyond our control. Our profitability may be adversely affected if we are unable to sell uncommitted production at favorable prices or at all.

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."

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

For the year ended December 31, 2014, we derived approximately 15% of our total coal revenues from sales to our three largest customers and approximately 38% 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.

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.

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. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon renewal of bonds. 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. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third party surety bond issuers under the terms of our financing arrangements.

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 recently opened offices in China, 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 flows.

Risks Related to Our Indebtedness

The amount of indebtedness we have incurred could significantly affect our business.

At December 31, 2014, we had consolidated indebtedness of approximately $5.2 billion. We also have significant lease and royalty obligations. Our ability to satisfy our debt, lease and royalty obligations, and our ability to refinance our indebtedness, will depend upon our future operating performance. Our ability to satisfy our financial obligations may be adversely affected if we incur additional indebtedness in the future. In addition, the amount of indebtedness we have incurred could have significant consequences to us, such as:

- limiting our ability to obtain additional financing to fund growth, such as new LBA acquisitions or other mergers and acquisitions, working capital, capital expenditures, debt service requirements or other cash requirements;
- exposing us to the risk of increased interest costs if the underlying interest rates rise;
- limiting our ability to invest operating cash flow in our business due to existing debt service requirements;
- making it more difficult to obtain surety bonds, letters of credit or other financing, particularly during weak credit markets;
- causing a decline in our credit ratings;
- limiting our ability to compete with companies that are not as leveraged and that may be better positioned to withstand economic downturns;
- limiting our ability to acquire new coal reserves and/or plant and equipment needed to conduct operations; and
- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we compete and general economic and market conditions.

If we further increase our indebtedness, the related risks that we now face, including those described above, could intensify. In addition to the principal repayments on our outstanding debt, we have other demands on our cash resources, including capital expenditures and operating expenses. Our ability to pay our debt depends upon our operating performance. In particular, economic conditions could cause our revenues to decline, and hamper our ability to repay our indebtedness. If we do not have enough cash to satisfy our debt service obligations, we may be required to refinance all or part of our debt, sell assets or reduce our spending. We may not be able to, at any given time, refinance our debt or sell assets on terms acceptable to us or at all.

We may be unable to comply with restrictions imposed by our credit facilities 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 maintain minimum levels of liquidity and various financial ratios and comply with various other financial covenants. Our ability to comply with these restrictions may be affected by events beyond our control. A failure to comply with these restrictions could adversely affect our ability to borrow under our credit facilities or result in an event of default under these agreements. In the event of a default, our lenders and the counterparties to our other financing arrangements could terminate their commitments to us and declare all amounts borrowed, together with accrued interest and fees, immediately due and payable. If this were to occur, we might not be able to pay these amounts, or we might be forced to seek an amendment to our financing arrangements which could make the terms of these arrangements more onerous for us. As a result, a default under one or more of our existing or future financing arrangements could have significant consequences for us. For more information about some of the restrictions contained in our credit facilities, leases and other financial arrangements, you should see the section entitled "Liquidity and Capital Resources."

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 are expected to be proposed or become effective in coming years. 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 is in the process of being developed, 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 or may install more effective pollution control equipment that reduces the need for low sulfur coal, possibly reducing future demand for coal and a reduced need to construct new coal-fueled power plants. The EIA's expectations for the coal industry assume there will be a significant number of as yet unplanned coal-fired plants built in the future which may not occur. 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 "Environmental and Other Regulatory Matters" for more information about the various governmental regulations affecting us.

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;
- 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'' 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 may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

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. 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 one of them thereafter was 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, which may have a favorable impact on our permits. The matter is pending before the U.S. District Court for the Southern District of West Virginia on Mingo Logan'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.

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. Certain recent developments particularly may cause changes in the legal and regulatory environment in which we operate and may impact our results or increase our costs or liabilities. Such legal and regulatory environment changes may include changes in: the processes for obtaining or renewing permits; costs associated with providing healthcare benefits to employees; health and safety standards; accounting standards; taxation requirements; and competition laws.

For example, in April 2010, the EPA issued comprehensive guidance regarding the water quality standards that EPA believes should apply to certain new and renewed Clean Water Act permit applications for Appalachian surface coal mining operations. Under the EPA's guidance, applicants seeking to obtain state and federal Clean Water Act permits for surface coal mining in Appalachia must perform an evaluation to determine if a reasonable potential exists that the proposed mining would cause a violation of water quality standards. According to the EPA Administrator, the water quality standards set forth in the EPA's guidance may be difficult for most surface mining operations to meet. Additionally, the EPA's guidance contains requirements for the avoidance and minimization of environmental and mining impacts, consideration of the full range of potential impacts on the environment, human health and local communities, including low-income or minority populations, and provision of meaningful opportunities for public participation in the permit process. The EPA's guidance is subject to several pending legal challenges related to its legal effect and sufficiency including consolidated challenges pending in the United States Court of Appeals for the District of Columbia Circuit led by the National Mining Association. We may be required to meet these requirements in the future in order to obtain and maintain permits that are important to our Appalachian operations. We cannot give any assurance that we will be able to meet these or any other new standards.

In response to the April 2010 explosion at Massey Energy Company's Upper Big Branch Mine and the ensuing tragedy, we expect that safety matters pertaining to underground coal mining operations will continue to be the topic of new legislation and regulation, as well as the subject of heightened enforcement efforts. For example, federal and West Virginia state authorities have announced special inspections of coal mines to evaluate several safety concerns, including the accumulation of coal dust and the proper ventilation of gases such as methane. In addition, both federal and West Virginia state authorities have announced that they are considering changes to mine safety rules and regulations which could potentially result in additional or enhanced required safety equipment, more frequent mine inspections, stricter and more thorough enforcement practices and enhanced reporting requirements. Any new environmental, health and safety requirements may increase the costs associated with obtaining or maintain permits necessary to perform our mining operations or otherwise may prevent, delay or reduce our planned production, any of which could adversely affect our financial condition, results of operations and cash flows.

Further, mining companies are entitled a tax deduction for percentage depletion, which may allow for depletion deductions in excess of the basis in the mineral reserves. The deduction is currently being reviewed by the federal government for repeal. If repealed, the inability to take a tax deduction for percentage depletion could have a material impact on our financial condition, results of operations, cash flows and future tax payments.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our Properties

General

At December 31, 2014, we owned or controlled, primarily through long-term leases, approximately 30,430 acres of coal land in Ohio, 21,832 acres of coal land in Maryland, 46,556 acres of coal land in Virginia, 407,453 acres of coal land in West Virginia, 107,665 acres of coal land in Wyoming, 266,654 acres of coal land in Illinois, 128,458 acres of coal land in Kentucky, 19,427 acres of coal land in Montana, 21,802 acres of coal land in New Mexico, 427 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 86,320 acres of our coal land from the federal government and approximately 24,956 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 occupy 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 5.1 billion tons of proven and probable recoverable reserves at December 31, 2014. Our coal reserve estimates at December 31, 2014 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 under the heading ''Risk Factors.''

The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2014:

Total Assigned Reserves
(Tons in millions)

	Total Assigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus) <1.2	1.2 - 2.5	>2.5	As Received Btus per lb.(1)	Reserve Control Leased	Owned	Mining Method Surface	Under-ground	Past Reserve Estimates 2012	2013
Wyoming	1,423	1,398	25	1,352	71	—	8,859	1,423	—	1,423	—	1,636	1,526
Montana	—	—	—	—	—	—	—	—	—	—	—	—	—
Utah	—	—	—	—	—	—	—	—	—	—	—	74	—
Colorado	65	58	7	65	—	—	11,473	65	—	—	65	80	84
Central App.	139	127	12	53	86	—	12,988	136	3	59	81	213	169
Northern App.	74	61	13	—	54	20	12,896	32	42	7	66	231	58
Illinois	33	21	12	—	—	33	10,772	29	4	—	33	18	21
Total	1,734	1,665	69	1,470	211	53	9,495	1,685	49	1,489	245	2,252	1,858

(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) <1.2	1.2 - 2.5	>2.5	As Received Btus per lb.(1)	Reserve Control Leased	Owned	Mining Method Surface	Under-ground
Wyoming	480	397	83	428	52	—	9,652	370	110	305	175
Montana	1,387	1,129	258	1,387	—	—	8,603	1,387	—	1,387	—
Utah	—	—	—	—	—	—	—	—	—	—	—
Colorado	26	20	6	26	—	—	11,194	26	—	—	26
Central App.	394	255	139	119	199	76	13,025	318	76	72	322
Northern App.	365	186	179	4	255	106	12,910	49	316	8	357
Illinois	678	339	339	1	51	626	10,969	65	613	2	676
Total	3,330	2,326	1,004	1,965	557	808	10,252	2,215	1,115	1,774	1,556

(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 68% 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 6% 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, 2014 was $4.8 billion, consisting of $77.9 million of prepaid royalties and a net book value of coal lands and mineral rights of $4.7 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 two to five years 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.''

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.

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 could limit our ability to mine our coal reserves or result in significant unanticipated costs'' contained under the heading ''Risk Factors'' for more information.

At December 31, 2014, approximately 23% 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 54,495 acres of property to other coal operators in 2014. We received royalty income of $9.6 million in 2014 from the mining of approximately 2.6 million tons, $9.5 million in 2013 from the mining of approximately 2.8 million tons and $10.0 million in 2012 from the mining of approximately 3.1 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, DC. In a Memorandum and Opinion and separate Order, each dated March 23, 2012, the federal court granted Mingo Logan's motion for summary judgment, vacated EPA's Final Determination and found valid and in full force Mingo Logan's Section 404 permit. As described more fully below, EPA appealed that order to the United States Court of Appeals for the DC circuit and by Opinion of the Court dated April 23, 2013, the court reversed the lower court's order and remanded the matter to the district court for further proceedings.

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 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 DC 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 where it is currently pending.

Allegheny Energy Contract Matter

Allegheny Energy Supply (''Allegheny''), the sole customer of coal produced at our subsidiary Wolf Run Mining Company's (''Wolf Run'') Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. (''Hunter Ridge''), and ICG in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claimed that Wolf Run breached a coal supply contract when it declared force majeure under the contract upon idling the Sycamore No. 2 mine in the third quarter of 2006, and that Wolf Run continued to breach the contract by failing to ship in volumes referenced in the contract. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped.

After extensive searching for gas wells and rehabilitation of the mine, it was re-opened in 2007, but with notice to Allegheny that it would necessarily operate at reduced volumes in order to safely and effectively avoid the many gas wells within the reserve. The amended complaint also alleged that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005. Allegheny voluntarily dropped the breach of representation claims later. Allegheny claimed that it would incur costs in excess of $100 million to purchase replacement coal over the life of the contract. ICG, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims.

On November 3, 2008, ICG, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and conspiracy. On September 23, 2009, Allegheny filed a second amended complaint alleging several alternative theories of liability in its effort to extend contractual liability to ICG, which was not a party to the original contract and did not exist at the time Wolf Run and Allegheny entered into the contract. No new substantive claims were asserted. ICG answered the second amended complaint on October 13, 2009, denying all of the new claims. The counterclaim was dismissed on motion for summary judgment entered on May 11, 2010. Allegheny's claims against ICG were also dismissed by summary judgment, but the claims against Wolf Run and Hunter Ridge were not. The court conducted a non-jury trial of this matter beginning on January 10, 2011 and concluding on February 1, 2011.

At the trial, Allegheny presented its evidence for breach of contract and claimed that it is entitled to past and future damages in the aggregate of between $228 million and $377 million. Wolf Run and Hunter Ridge presented their defense of the claims, including evidence with respect to the existence of force majeure conditions and excuse under the contract and applicable law. Wolf Run and Hunter Ridge presented evidence that Allegheny's damages calculations were significantly inflated because it did not seek to determine damages as of the time of the breach and in some instances artificially assumed future nondelivery or did not take into account the apparent requirement to supply coal in the future. On May 2, 2011, the trial court entered a Memorandum and Verdict determining that Wolf Run had breached the coal supply contract and that the performance shortfall was not excused by force majeure. The trial court awarded total damages and interest in the amount of $104.1 million, which consisted of $13.8 million for past damages, and $90.3 million for future damages. ICG and Allegheny filed post-verdict motions in the trial court and on August 23, 2011, the court denied the parties' motions. The court entered a final judgment on August 25, 2011, in the amount of $104.1 million, which included pre-judgment interest.

The parties appealed the lower court's decision to the Superior Court of Pennsylvania. On August 13, 2012, the Superior Court of Pennsylvania affirmed the award of past damages, but ruled that the lower court should have calculated future damages as of the date of breach, and remanded the matter back to the lower court with instructions to recalculate that portion of the award. On November 19, 2012, Allegheny filed a Petition for Allowance of Appeal with the Supreme Court of Pennsylvania and Wolf Run and Hunter Ridge filed an Answer. On July 2, 2013, the Supreme Court of Pennsylvania denied the Petition of Allowance. As this action finalized the past damage award, Wolf Run paid $15.6 million for the past damage amount, including interest, to Allegheny in July 2013. Testimony on the future damage award in the lower court concluded on May 19, 2014, and post-trial briefs and responses were submitted on August 8, 2014. The court held a hearing on this matter on November 5, 2014 and on February 16, 2015 awarded Allegheny $7.5 million plus interest for the future damages.

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, 2014.

PART II

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

Market for Registrant's Common Equity and Related Stockholder Matters

Our common stock is listed and traded on the New York Stock Exchange under the symbol "ACI". On February 13, 2015, our common stock closed at $1.19 on the New York Stock Exchange. On that date, there were approximately 5,500 holders of record of our common stock.

Holders of our common stock are entitled to receive dividends when they are declared by our board of directors. Prior to 2014 dividends declared on common stock were historically paid in mid-March, June, September and December. In 2014, we paid an annual dividend in March. In 2015, we announced that we would not pay an annual dividend. We paid dividends on our common stock totaling $2.1 million, or $0.01 per share, in 2014, and $25.5 million, or $0.12 per share, in 2013. There is no assurance as to the amount or payment of dividends in the future because they are dependent on our future earnings, capital requirements, financial condition, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors. You should see Note 13, Debt and Financing Arrangements, beginning on Page F-27 for more information about restrictions on our ability to declare dividends.

The following table sets forth for each period indicated the dividends paid per common share, the high and low sale prices of our common stock for each of the quarterly periods indicated.

	2014			
	March 31	June 30	September 30	December 31
Dividends per common share	$0.01	—	—	—
High	4.98	5.37	3.73	2.93
Low	3.79	3.15	2.01	1.35

	2013			
	March 31	June 30	September 30	December 31
Dividends per common share	$0.03	$0.03	$0.03	$0.03
High	7.95	5.82	5.25	4.77
Low	4.89	3.47	3.60	3.75

Stock Price Performance Graph

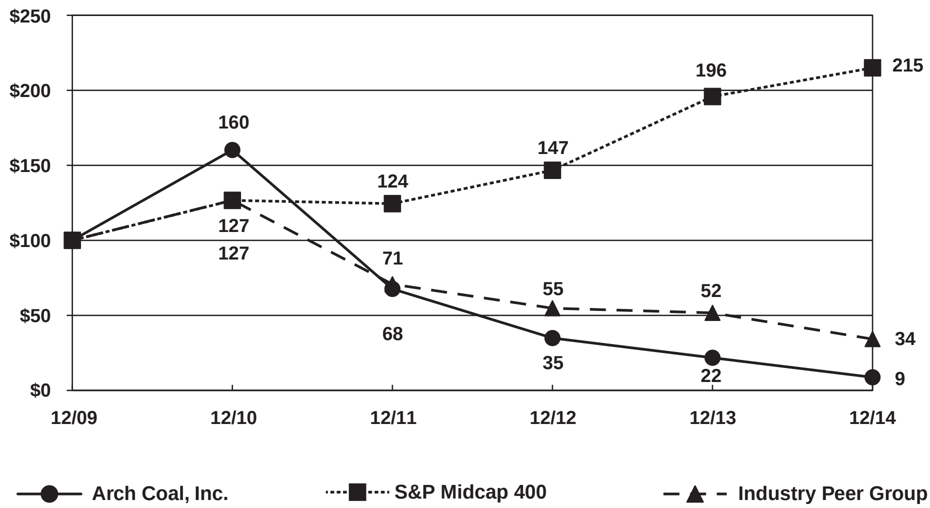
The following performance graph compares the cumulative total return to stockholders on our common stock with the cumulative total return on two indices: a peer group, consisting of CONSOL Energy, Inc., Alpha Natural Resources, Inc. and Peabody Energy Corp., and the Standard & Poor's (S&P) 400 (Midcap) Index. The graph assumes that:

- you invested $100 in Arch Coal common stock and in each index at the closing price on December 31, 2009;
- all dividends were reinvested;
- annual reweighting of the peer groups; and
- you continued to hold your investment through December 31, 2014.

You are cautioned against drawing any conclusions from the data contained in this graph, as past results are not necessarily indicative of future performance. The indices used are included for comparative purposes only and do not indicate an opinion of management that such indices are necessarily an appropriate measure of the relative performance of our common stock.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Arch Coal, Inc., the S&P Midcap 400 Index
and an Industry Peer Group



* $100 invested on 12/31/09 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	12/09	12/10	12/11	12/12	12/13	12/14
Arch Coal, Inc.	100.00	160.21	67.62	34.87	21.74	8.72
S&P Midcap 400	100.00	126.64	124.45	146.69	195.84	214.97
Industry Peer Group	100.00	126.72	70.75	54.74	51.66	34.19

Issuer Purchases of Equity Securities

In September 2006, our board of directors authorized a share repurchase program for the purchase of up to 14,000,000 shares of our common stock. There is no expiration date on the current authorization, and we have not made any decisions to suspend or cancel purchases under the program. We did not purchase any shares of our common stock under this program during the fiscal year ended December 31, 2014. As of December 31, 2014, we have purchased 3,074,200 shares of our common stock under this program since the board of directors authorized the program. Based on the closing price of our common stock as reported on the New York Stock Exchange on February 13, 2015, there is approximately $13.0 million of our common stock that may yet be purchased under this program.

ITEM 6. SELECTED FINANCIAL DATA.

(In thousands, except per share data)	Year Ended December 31 2014	2013(1)	2012(2)	2011(3)	2010(4)(5)
Statement of Operations Data:					
Revenues	$2,937,119	$3,014,357	$ 3,768,126	$ 3,883,039	$2,817,441
Mine closure and asset impairment costs	24,113	220,879	539,182	7,316	—
Goodwill impairment	—	265,423	330,680	—	—
Acquisition and transition costs	—	—	—	47,360	—
Income (loss) from operations	(149,531)	(663,141)	(757,012)	343,061	291,782
Interest expense	(390,946)	(381,267)	(317,615)	(230,186)	(142,549)
Non-operating expenses	—	(42,921)	(23,668)	(51,448)	(6,776)
Income (loss) from continuing operations	(558,353)	(745,228)	(738,915)	89,015	131,364
Diluted earnings (loss) from continuing operations per common share	$ (2.63)	$ (3.52)	$ (3.50)	$ 0.47	$ 0.62
Net income (loss) attributable to Arch Coal	(558,353)	(641,832)	(683,955)	141,683	158,857
Basic earnings (loss) per common share	$ (2.63)	$ (3.03)	$ (3.24)	$ 0.75	$ 0.98
Diluted earnings (loss) per common share	$ (2.63)	$ (3.03)	$ (3.24)	$ 0.74	$ 0.97
Balance Sheet Data:					
Total assets	$8,429,723	$8,990,193	$10,006,777	$10,213,959	$4,880,769
Working capital	1,023,357	1,293,849	1,337,035	162,106	207,568
Long-term debt, less current maturities	5,123,485	5,118,002	5,085,879	3,762,297	1,538,744
Other long-term obligations	695,881	717,174	825,080	864,667	566,728
Noncurrent deferred income tax liability	422,809	413,546	664,182	976,753	—
Arch Coal stockholders' equity	1,668,154	2,253,249	2,854,567	3,578,040	2,237,507
Common Stock Data:					
Dividends per share	$ 0.01	$ 0.12	$ 0.20	$ 0.43	$ 0.39
Shares outstanding at year-end	212,274	212,280	212,247	211,671	162,605
Cash Flow Data:					
Cash provided by operating activities	(33,582)	55,742	332,804	642,242	697,147
Depreciation, depletion and amortization, including amortization of acquired sales contracts, net	405,561	438,247	500,319	444,518	400,672
Capital expenditures	147,286	296,984	395,225	540,936	314,657
Acquisitions of businesses, net of cash acquired	—	—	—	2,894,339	—
Net proceeds from the issuance of long term debt	(4,519)	623,511	1,942,685	1,906,306	500,000
Net proceeds from the sale of common stock	—	—	—	1,267,933	—
Payments to retire debt, including redemption premium	—	628,660	452,934	605,178	505,627
Net increase (decrease) in borrowings under lines of credit and commercial paper program	—	—	(481,300)	424,396	(196,549)
Dividend payments	2,123	25,475	42,440	80,748	63,373
Operating Data:					
Tons sold	134,360	139,607	140,820	156,897	162,763
Tons produced	132,614	136,613	135,934	151,829	156,282
Tons purchased from third parties	1,182	2,925	4,327	5,557	6,825

(1) 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. See Note 3 to the consolidated financial statements, "Discontinued Operations," for further information.

(2) 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 $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.

(3) On June 15, 2011, we completed our acquisition of ICG, a leading coal producer, adding 12 mining complexes in Appalachia, one complex in the Illinois Basin and one mine under development in Appalachia, along with other coal reserves not currently in development. To finance the acquisition, we sold 48.7 million shares of our common stock and issued $2.0 billion in aggregate principal amount of senior unsecured notes. We directly expensed costs related to the financing and acquisition of $104.2 million.

(4) In the second quarter of 2010, we exchanged 68.4 million tons of coal reserves in the Illinois Basin for an additional 9% ownership interest in Knight Hawk Holdings, LLC (Knight Hawk), increasing our ownership to 42%. We recognized a pre-tax gain of $41.6 million on the transaction, representing the difference between the fair value and net book value of the coal reserves, adjusted for our retained ownership interest in the reserves through the investment in Knight Hawk.

(5) On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 at par. We used the net proceeds from the offering and cash on hand to fund the redemption on September 8, 2010 of $500.0 million aggregate principal amount of our outstanding 6.75% senior notes due in 2013 at a redemption price of 101.125%. We recognized a loss on the redemption of $6.8 million.

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

Overview

Our results in 2014 were impacted by the continuing weakness in coal markets. In addition, thermal coal shipments in 2014 were impacted by rail network issues in the Powder River Basin earlier in 2014, though service improved in the latter half of the year. Unfavorable weather patterns in 2014, including an unseasonably mild summer followed by a warmer than expected December, also dampened domestic coal consumption.

Seaborne coal markets remain challenged, as oversupply continues to pressure global prices for metallurgical and thermal coals. We have limited our forward exposure to the export market at this time, but we have maintained our ability to increase export shipments should fundamentals improve.

We reduced cash costs in our Powder River Basin and Appalachian regions over the course of 2014, including freezing benefits under our pension plans, and further reduced our capital outlays over 2013 levels. Our thermal portfolio is substantially committed for 2015 at prices above what we achieved in our main thermal segments in 2014. See further information regarding committed sales in Item 7A. "Quantitative and Qualitative Disclosures About Market Risk."

Operational Performance

The following table shows operating results of continuing coal operations for the years ended December 31, 2014, 2013 and 2012. The "other" category includes the results of our other bituminous thermal operations, our West Elk mining complex in Colorado and our Viper mining complex in Illinois.

	Year Ended December 31,		
	2014	2013	2012
Powder River Basin			
Tons sold (in thousands)	111,156	111,653	104,394
Coal sales per ton sold	$ 12.86	$ 12.44	$ 13.61
Cost per ton sold	$ 12.58	$ 12.18	$ 12.79
Operating margin per ton sold	$ 0.28	$ 0.26	$ 0.82
Adjusted EBITDA (in thousands)	$198,074	$206,910	$262,155
Appalachia			
Tons sold (in thousands)	14,484	14,224	18,717
Coal sales per ton sold	$ 68.77	$ 73.07	$ 85.06
Cost per ton sold	$ 77.59	$ 81.27	$ 84.09
Operating loss per ton sold	$ (8.82)	$ (8.20)	$ 0.97
Adjusted EBITDA (in thousands)	$110,693	$ 88,883	$405,981
Other			
Tons sold (in thousands)	8,720	8,422	8,820
Coal sales per ton sold	$ 30.78	$ 32.63	$ 34.39
Cost per ton sold	$ 25.44	26.95	26.91
Operating margin per ton sold	$ 5.34	$ 5.68	$ 7.48
Adjusted EBITDA (in thousands)	$ 58,586	$ 91,642	$114,882

This table reflects numbers reported under a basis that differs from U.S. GAAP. See the "Reconciliation of Non-GAAP measurements" 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 EBITDA decreased 4% in 2014 when compared to 2013 due to a decrease of shipment volumes partially offset by higher per-ton operating margins. Our pricing improved in the region, which partially offset the impact of the lower shipment levels and higher costs. Higher pricing is attributable primarily to a decrease in export shipments and contracting in stronger markets. Higher costs were the result of repairs and maintenance in earlier quarters of 2014 that were incurred in anticipation of an increase in shipment volumes to meet expected higher regional demand; however, rail performance issues impacted shipments out of the region. Rail performance did improve later in the year over previous quarters, but 2014 shipments ended the year lower than the prior year.

Adjusted EBITDA decreased in 2013 when compared to 2012 due to continued weak coal market conditions, which resulted in lower per-ton realizations. Per-ton costs decreased slightly in 2013 when compared with 2012 as a result of cost control efforts and the increase in sales volumes, as well as a decrease in production taxes and royalties that fluctuate with selling prices ($0.24 per ton).

Appalachia—Adjusted EBITDA increased in 2014 when compared to 2013 due to the sale of operating and idled thermal coal mines in Kentucky ($20.6 million). See Note 3, ''Divestitures'', to the condensed consolidated financial statements for further discussion. The gains were partially offset by the impact of an increase in per ton operating losses, caused by lower pricing for both metallurgical and thermal coal. The startup of the longwall at the Leer mining complex, the idling and divesting of higher-cost production, and lower sales-sensitive costs contributed to lower per-ton costs, which largely offset the impact of lower sales pricing.

Segment Adjusted EBITDA decreased significantly in 2013 when compared to 2012 due to the weaker coal market conditions, which resulted in lower coal sales volumes and also lower average coal pricing. The decrease in pricing was particularly pronounced on metallurgical coal shipments. We sold 6.8 million tons of metallurgical-quality coal in 2013 compared to 7.5 million tons in 2012. Part of the 24% decrease in volumes in Appalachia was also due to geologic issues at the Mountain Laurel mine, which continued through the first quarter of 2014. Per-ton costs have decreased, despite the significant decrease in sales volumes, as we closed higher-cost coal operations in 2012 in response to the challenging market conditions, which contributed approximately $5 to cost per ton in 2012. Cost containment and efficiency efforts also contributed to lower costs in 2013, as did a decrease in production taxes and royalties that fluctuate with selling prices, which decreased $1.07 per ton in 2013 when compared with 2012.

Other—Operating margin per ton and Adjusted EBITDA decreased in 2014 and 2013 when compared with the respective prior year due to lower coal risk management settlements, partially offset by the impact of cost control efforts. In 2013, lower price realizations were due to weak thermal coal markets.

Results of Operations

The following tables reflect the amounts as presented in our consolidated statements of operations. Individual line items exclude the results of Canyon Fuel, including the gain on the sale, as those amounts are presented as one line item, ''Income from discontinued operations, including gain on sale—net of tax'', in the consolidated statements of operations.

Items impacting comparability of results

We recorded fixed asset impairment charges related of approximately $142.8 million and goodwill impairment charges of $265.4 million during 2013.

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 $422.7 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. See Note 3 to the consolidated financial statements, "Divestitures," for further information.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

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, 2014 and compares it with the information for the year ended December 31, 2013:

	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase (Decrease)
	(In thousands)		
Coal sales	$2,935,181	$3,000,476	$(65,295)
Tons sold	134,360	134,300	60

Coal sales decreased in the year ended December 31, 2014 from the year ended December 31, 2013 on a consolidated basis, primarily due to the impact of lower average per-ton pricing (a decrease of approximately $66 million). Average pricing decreased slightly from $22.34 to $21.85 per ton, primarily due to declines in export shipments, as fluctuations in regional pricing offset each other. See discussion in "Regional Performance" 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, 2014 and compares it with the information for the year ended December 31, 2013:

	Year Ended December 31, 2014	Year Ended December 31, 2013	(Increase) Decrease in Net Loss
	(In thousands)		
Cost of sales (exclusive of items shown separately below)	$2,566,193	$2,663,136	$ 96,943
Depreciation, depletion and amortization	418,748	426,442	7,694
Amortization of acquired sales contracts, net	(13,187)	(9,457)	3,730
Change in fair value of coal derivatives and coal trading activities, net	(3,686)	7,845	11,531
Asset impairment and mine closure costs	24,113	220,879	196,766
Goodwill impairment	—	265,423	265,423
Selling, general and administrative expenses	114,223	133,448	19,225
Other operating income, net	(19,754)	(30,218)	(10,464)
Total costs, expenses and other	$3,086,650	$3,677,498	$590,848

Cost of sales. Our cost of sales decreased in the year ended December 31, 2014 from the year ended December 31, 2013, due to a decrease in transportation costs (approximately $83 million) and the sale of the ADDCAR subsidiary ($11.9 million). See discussion in "Regional Performance" for information about regional cost results.

Depreciation, depletion and amortization. When compared with the year ended December 31, 2013, depreciation, depletion and amortization costs decreased in the year ended December 31, 2014 due to lower overall production and capital spending levels.

Asset impairment and mine closure costs. In the face of weak coal markets, management has chosen to concentrate metallurgical coal production at our lowest-cost and highest-margin operations. In the third quarter of 2014, we idled an additional metallurgical coal mining complex in Appalachia, where we had previously idled two contract mining operations. We have retained the option to restart production at this complex should metallurgical coal markets strengthen. In the third quarter of 2013, in response to market conditions, we recorded impairment charges related to a Kentucky coal operation and our highwall mining equipment subsidiary. In addition, we recorded an other-than-temporary impairment of investments in equity method investees and related loans receivable. See further discussion in the consolidated financial statements Note 5, "Impairment Charges and Mine Closure Costs" and Note 9, "Equity Method Investments and Membership Interests in Joint Ventures".

Selling, general and administrative expenses. Total selling, general and administrative expenses decreased when compared with the year ended December 31, 2013, due to decreases in legal and professional fees ($6.5 million), lower costs related to our pension plans ($8.5 million), and decreases in discretionary spending.

Other operating income, net. When compared with the year ended December 31, 2013, other operating income, net decreased during the year ended December 31, 2014, primarily as a result of costs of $36.5 million in the year ended December 31, 2014 related to export shortfalls under throughput arrangements (an increase of $24.8 million from the year ended December 31, 2013), and a decrease in realized gains of $26.6 million on derivatives used to manage coal price risk. These were offset by an increase in gains on asset disposals of $22.9 million, primarily from the divestitures of mining operations in the Appalachia region and our ADDCAR subsidiary, and a decrease in contract settlement losses of $10.9 million.

Provision for (benefit from) income taxes. The following table summarizes our benefit from income taxes for the year ended December 31, 2014 and compares it with the information for the year ended December 31, 2013:

	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase in Net Loss
	(In thousands)		
Provision for (benefit from) income taxes	$25,634	$(335,498)	$(361,132)

The income tax provision in the year ended December 31, 2014 compared to an effective rate of 31% on our pretax loss in the year ended December 31, 2013 was the result of the establishment of a valuation allowance totaling approximately $227 million relating to 2014 federal and state net operating loss carryforwards. See further discussion in Note 14," Taxes", to the condensed consolidated financial statements for further discussion.

Income from discontinued operations, net of tax. The results of our Canyon Fuel subsidiary prior to its divestiture, including the gain on divestiture, are segregated from continuing operations. See further information in Note 3, "Divestitures", to the condensed consolidated financial statements.

	Year Ended December 31, 2014	2013	Increase in Net Loss
	(In thousands)		
Income from discontinued operations, net of tax	$—	$103,396	$(103,396)

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Coal sales. The following table compares information about coal sales during the year ended December 31, 2013 with the information for the year ended December 31, 2012:

	Year Ended December 31, 2013	2012	Increase (Decrease)
	(In thousands)		
Coal sales	$3,000,476	$3,747,971	$(747,495)
Tons sold	134,300	131,931	2,369

Coal sales decreased approximately 20% in 2013 compared with 2012 due to lower realized prices. Lower average realizations per ton sold, the result of the weak coal markets, including a decrease in export sales, and a lower percentage of higher-priced coal sales out of Appalachia, resulted in a decrease in coal sales revenues of approximately $456 million. The increase in sales volumes in our Powder River Basin segment ($99 million) was offset by the impact of lower volumes from Appalachia and other segments ($390 million).

Costs, expenses and other. The following table compares costs, expenses and other components of operating income for the year ended December 31, 2013 with the information for the year ended December 31, 2012:

	Year Ended December 31, 2013	2012	(Increase) Decrease in Net Loss
	(In thousands)		
Cost of sales (exclusive of items shown separately below)	$2,663,136	$3,155,099	$491,963
Depreciation, depletion and amortization	426,442	492,211	65,769
Amortization of acquired sales contracts, net	(9,457)	(25,189)	(15,732)
Change in fair value of coal derivatives and coal trading activities, net	7,845	(16,590)	(24,435)
Coal derivative settlements, non-hedging			
Asset impairment and mine closure costs	220,879	539,182	318,303
Goodwill impairment	265,423	330,680	65,257
Contract settlement resulting from Patriot Coal bankruptcy	—	58,335	58,335
Reduction in accrual related to acquired litigation	—	(79,532)	(79,532)
Selling, general and administrative expenses	133,448	134,299	851
Other operating income, net	(30,218)	(63,357)	(33,139)
Total costs, expenses and other	$3,677,498	$4,525,138	$847,640

Cost of sales. Our cost of sales decreased in 2013 from 2012 primarily due to lower average per-ton production costs ($409 million), the result of a change in regional mix that reflects lower sales volumes from the Appalachia segment. In addition, transportation costs decreased $133 million in 2013 from 2012 due to a decrease in export shipments. The increase in sales volumes resulted in an increase of $42 million in cost of sales. These factors are discussed in detail in the "Operational performance" section.

Depreciation, depletion and amortization. When compared with 2012, depreciation, depletion and amortization costs decreased in 2013 due to asset impairments and the decreases in production in the Appalachia and other segments for the respective periods, including the impact of mine closures in 2012.

Change in fair value of coal derivatives and coal trading activities, net. The gains reflected in 2012 relate primarily to positions taken in 2012 in the API-2 market, the derivatives market for coal delivered into Europe. We entered into these positions taken in 2012 to manage price risk on physical export sales into Europe. As these positions are not accounted for as hedges, changes in the positions' fair value prior to settlement are recognized in this line on the consolidated statement of operations. When the positions settle, the realized gains and losses are reclassified to "Other income, net". The decrease from gains in 2012 to losses in 2013 is the result of a decrease in positions outstanding, due to settlements during the year.

Asset impairment and mine closure costs. In response to market conditions, we recorded impairment charges in 2013 related to a Kentucky coal operation and our highwall mining equipment subsidiary. In addition, we recorded other-than-temporary impairment charges related to equity method investees. In 2012, we closed or idled five mining operations in response to market conditions. See further discussion in Note 5 ,"Impairment Charges and Mine Closure Costs", and Note 9, "Equity Method Investments and Membership Interests in Joint Ventures", to the consolidated financial statements.

Goodwill impairment. In 2012, we recognized an impairment charge of $115.8 million, the entire balance of goodwill allocated to our Black Thunder mining complex, due to expectations of lower thermal coal demand and its impact on near-term sales volumes and pricing, and $214.9 million related to two of four operating units that were allocated goodwill in the acquisition of ICG, due to a drop in near-term metallurgical coal prices. The remaining $265.4 million of goodwill from the ICG acquisition was impaired in the fourth quarter of 2013, as a result of continuing weakness in the metallurgical coal markets. See further discussion in "Critical Accounting Policies".

Contract settlement resulting from Patriot Coal bankruptcy. In the fourth quarter of 2012, Patriot Coal's rejection of their supply agreement with us was approved by the bankruptcy court. We then agreed to a settlement of a contract that had been supplied by Patriot Coal. We will make annual payments through 2017 under this obligation.

Reduction in accrual related to acquired litigation. As a result of a 2012 legal ruling in a lawsuit against former ICG subsidiaries, we changed our assessment of the probable loss related to the lawsuit. The suit is discussed in detail in Note 25, "Commitments and Contingencies" to the consolidated financial statements.

Selling, general and administrative expenses. Selling, general and administrative expenses in 2013 decreased slightly when compared with 2012, due to lower discretionary spending levels in 2013, which were partially offset by the impact of lower bonus and incentive plan costs in 2012 as certain performance targets were not achieved in 2012. Cost reductions in 2013 were achieved primarily through a decrease in industry group dues and fees of $6.4 million, and decreases in legal and other professional fees.

Other operating expense (income), net. When compared with 2012, other operating income decreased in 2013 due to an increase in liquidated damages on throughput commitment of $9.4 million in 2013, a decrease in commercial-related income decreased of $17.9 million, decreased gains on asset sales from $11.8 million in 2012 to $4.6 million in 2013, and a decrease in realized gains of $11.5 million on derivatives used to manage coal price risk. These items were partially offset by a decrease in unrealized losses relating to our diesel purchase and fuel surcharge risk management programs of $11.3 million.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2013 and compares it with the information for the year ended December 31, 2012:

	Year Ended December 31,		(Increase) Decrease
	2013	2012	in Net Loss
	(In thousands)		
Interest expense	$(381,267)	$(317,615)	$(63,652)
Interest and investment income	6,603	5,473	1,130
	$(374,664)	$(312,142)	$(62,522)

The increase in interest expense is due to an increase in our outstanding debt in 2013 when compared with 2012, primarily as a result of financing transactions completed during 2012, which resulted in a net increase in debt outstanding of over $1 billion.

Non-operating expense. The following table summarizes non-operating expense for the year ended December 31, 2013 and compares it with the information for the year ended December 31, 2012:

	Year Ended December 31,		Increase (Decrease) in Net Loss
	2013	2012	$
	(In thousands)		
Net loss resulting from early retirement and refinancing of debt	$(42,921)	$(23,668)	$(19,253)

Amounts reported as nonoperating consist of expenses resulting from financing activities, other than interest costs. In the fourth quarter of 2013, we retired our 8.75% senior notes due in 2016 and reduced the capacity of our revolving credit facility, in conjunction with a refinancing discussed in the "Liquidity" section. As a result, we paid a tender premium and wrote off unamortized discount and fees. During 2012, nonoperating expense consists primarily of the write-off of financing fees relating to decreases in our revolving credit facility capacity.

Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion.

	Year Ended December 31,		Increase
	2013	2012	in Net Loss
	(In thousands)		
Provision for (benefit from) income taxes	$(335,498)	$(353,907)	$(18,409)

In 2013 and 2012, our benefit was impacted by $70.3 million and $56.9 million, respectively, of non-deductible goodwill adjustments and $8.7 million and $31.8 million, respectively, to increase our valuation allowance against state and foreign tax carryforwards.

Income from discontinued operations, net of tax. Canyon Fuel's results and the $77.0 million gain from its sale in 2013, net of the related income tax impacts, are segregated from continuing operations.

	Year Ended December 31, 2013	2012	Increase in Net Loss
	(In thousands)		
Income from discontinued operations, net of tax	$103,396	$55,228	$(48,168)

See Note 3 "Discontinued Operations", to the consolidated financial statements for further information.

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 tons sold are adjusted for transportation costs, and may be adjusted for other items that, due to accounting rules, 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 better reflects our revenue for the quality of coal sold and our operating results by including all income from coal sales. The adjustments made to arrive at these measures are significant in understanding and assessing our financial condition. Therefore, segment coal sales revenues should not be considered in isolation, nor as an alternative to coal sales revenues under generally accepted accounting principles.

	Year Ended December 31, 2014	2013	2012
Reported coal sales revenues	$2,693,898	$2,702,865	$3,322,366
Coal risk management derivative settlements classified in "other income"	(5,958)	(32,535)	(37,871)
Transportation costs	247,241	330,146	463,476
Coal sales	2,935,181	3,000,476	3,747,971
Other revenues	$ 1,938	$ 13,881	$ 20,155
Revenues in the consolidated statements of operations	$2,937,119	$3,014,357	$3,768,126

Segment cost per ton sold

Segment costs per ton sold are calculated as the segment's cost of tons sold 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 accounting rules, 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.

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Reported cost of coal sales	$2,743,182	$2,743,766	$3,149,721
Diesel fuel risk management derivative settlements classified in "other income"	(6,789)	(14,939)	(11,253)
Transportation costs	247,241	330,146	463,476
Depreciation, depletion and amortization in reported segment cost of tons sold presented on separate line on statement of operations	(414,379)	(418,736)	(487,670)
Other (other operating segments, operating overhead, etc.)	(3,062)	22,899	40,825
Cost of sales in the consolidated statements of operations	$2,566,193	$2,663,136	$3,155,099

Reconciliation of Segment Adjusted EBITDA to Net Income

The discussion in "Results of Operations" includes references to our Adjusted EBITDA. Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. We believe that Adjusted EBITDA presents a useful measure of our ability to service existing debt and incur additional debt based on ongoing operations. Investors should be aware that our presentation of

Adjusted EBITDA may not be comparable to similarly titled measures used by other companies. The table below shows how we calculate Adjusted EBITDA.

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Reported adjusted EBITDA from coal operations	$ 367,353	$ 387,435	$ 783,018
EBITDA from discontinued operations	—	173,776	108,850
Corporate and other[(1)]	(87,210)	(135,289)	(203,414)
Adjusted EBITDA	280,143	425,922	688,454
Income tax benefit	(25,634)	335,498	353,907
Interest expense, net	(383,188)	(374,664)	(312,142)
Depreciation, depletion and amortization	(418,748)	(426,442)	(492,211)
Amortization of acquired sales contracts, net	13,187	9,457	25,189
Asset impairment costs	(24,113)	(220,879)	(539,182)
Goodwill impairment	—	(265,423)	(330,680)
Other nonoperating expenses	—	(42,921)	(23,668)
Settlement of UMWA legal claims	—	(12,000)	—
Interest, depreciation, depletion and amortization classified as discontinued operations	—	(70,380)	(53,622)
Net loss	$(558,353)	$(641,832)	$(683,955)

(1) Corporate and other Adjusted EBITDA includes primarily selling, general and administrative expenses, income from our equity investments and certain changes in the fair value of coal derivatives and coal trading activities.

Liquidity and Capital Resources

Our primary sources of cash are coal sales to customers, borrowings under our credit facilities and other financing arrangements, and debt and equity offerings related to significant transactions or refinancing activity. Excluding any significant mineral reserve acquisitions, we generally satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations, cash on hand or borrowings under our lines of credit. Such plans are subject to change based on our cash needs.

With financing transactions in recent years, we have implemented a flexible capital structure, with high levels of pre-payable debt, which should allow us to de-lever our balance sheet, should markets and our cash flows improve. In addition, we regularly evaluate our capital structure and may make debt purchases for cash and/or exchanges for debt or equity from time to time through tender offers, open market purchases, private transactions, or otherwise, or seek to raise additional debt or equity, depending on market conditions and covenant restrictions. We have no meaningful maturities of debt until 2018, and we have suspended or eliminated most financial maintenance covenants that pertain only to our $250 million revolver until June of 2015, when a senior secured leverage ratio covenant becomes effective. Until then, only a minimum liquidity covenant of $550 million remains in place. We had liquidity of $1.2 billion at December 31, 2014, with $983.2 million of that in cash and liquid securities. We have no borrowings outstanding under our revolving credit agreement at December 31, 2014.

During the market down cycle our focus has been to preserve liquidity and prudently manage costs, including capital expenditures. Our thermal coal commitments reflect prices above what we achieved in 2014 in our PRB and Bituminous Thermal segments and our metallurgical coal production is 60% committed for 2015. See further information about our sales commitments in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Cash provided by (used in):			
Operating activities	(33,582)	55,742	332,804
Investing activities	(105,756)	125,445	(649,166)
Financing activities	(37,530)	(54,710)	962,835

The decrease in our operating profitability resulting from weak coal market condition impacted cash from operating activities during the year ended December 31, 2014 compared to the year ended December 31, 2013 and in the year ended December 31, 2013 compared to the year ended December 31, 2012. In addition to divesting non-core and less profitable operations, the Company reduced production costs over the course of 2014 in an effort to improve operating cash flows.

We used $105.8 million of cash in investing activities during the year ended December 31, 2014, compared to generating $125.4 million of cash in the year ended December 31, 2013, and using $649.2 million of cash in the year ended December 31, 2012, as we received $422.7 million from the divestiture of the Canyon Fuel operations in 2013 compared to $46.7 million from divestitures in 2014. Capital expenditures and additions to prepaid royalties decreased approximately $157 million and $97 million, respectively, during 2014 and 2013 when compared to the previous year due to the startup of the Leer mining complex longwall in the first quarter of 2014 and cash management efforts. In 2013 and 2012, we focused our spending on expanding our metallurgical coal production capacity, and in 2013 and 2012 we spent approximately $109 million, net of proceeds from the sale and leaseback of longwall shields, and $195 million on the development of the Leer mining complex. With the proceeds from our 2012 financing activities discussed below, we purchased short term investments, and net reinvestment in those securities totaled $6.3 million and $19.2 million in 2014 and 2013, respectively. In 2012, we also purchased the noncontrolling interest in Arch Western for $17.5 million.

Cash used in financing activities was approximately $37.5 million and $54.7 million in 2014 and 2013, compared to cash provided by financing activities of $962.8 million in 2012. In 2012, proceeds from the term loan in conjunction with the refinancing of our revolving credit facility were used, in part, to retire the remaining outstanding senior secured notes due in 2013 and the outstanding borrowings under our lines of credit. In 2013, we borrowed an additional $300.0 million face amount on the term loan and issued $350.0 million 8.00% senior notes due in 2019 to retire 8.75% senior unsecured notes due 2016 for $628.7 million, extending our earliest debit maturities to 2018. See further information about our outstanding debt balances in Note 13 "Debt and Financing Arrangements" to the consolidated financial statements. The decrease in the dividend rate from $0.11 per quarter to $0.03 per quarter in the second quarter of 2012 and to $0.01 per annum in the first quarter of 2014 reduced dividends paid from $42.4 million to $25.5 million to $2.1 million during 2012, 2013 and 2014, respectively. We eliminated the dividend in the first quarter of 2015 to further preserve liquidity.

Ratio of Earnings to Fixed Charges

The following table sets forth our ratios of earnings to combined fixed charges and preference dividends for the periods indicated:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Ratio of earnings to fixed charges[1]	N/A[2]	N/A[2]	N/A	1.25x	1.92x

(1) Earnings consist of income from continuing operations before income taxes and are adjusted to include only distributed income from affiliates accounted for on the equity method and fixed charges (excluding capitalized interest). Fixed charges consist of interest incurred on indebtedness, the portion of operating lease rentals deemed representative of the interest factor and the amortization of debt expense.

(2) Total losses for the ratio calculation were $100.2 million and total fixed charges were $404.5 million for the year ended December 31, 2014. Total losses for the ratio calculation were $638.3 million and total fixed charges were $450.7 million for the year ended December 31, 2013. Total losses for the ratio calculation were $711.2 million and total fixed charges were $367.2 million for the year ended December 31, 2012.

Contractual Obligations

	Payments Due by Period				
	2015	2016 - 2017	2018 - 2019	after 2019	Total
	(Dollars in thousands)				
Long-term debt, including related interest	$377,406	$ 740,948	$4,027,210	$1,633,745	$6,779,309
Operating leases	25,685	36,307	9,704	11,880	83,576
Coal lease rights	89,975	96,564	31,459	83,282	301,280
Coal purchase obligations	47,814	27,921	—	—	75,735
Unconditional purchase obligations	217,759	204,933	155,722	279,409	857,823
Total contractual obligations	$758,639	$1,106,673	$4,224,095	$2,008,316	$8,097,723

The related interest on long-term debt was calculated using rates in effect at December 31, 2014 for the remaining term of outstanding borrowings.

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

Our coal purchase obligations include purchase obligations in the over-the-counter market, as well as unconditional purchase obligations with coal suppliers.

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 $418.1 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'', 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. You should 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. You should see the section entitled ''Critical Accounting Policies'' for more information about these assumptions. We expect to make contributions of $0.5 million to our pension plans in 2015, 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.

You should 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.

The table above excludes future contingent payments of up to $58.5 million related to development financing for certain of our equity investees. Our obligation to make these payments, as well as the timing of any payments required, is contingent upon a number of factors, including project development progress, receipt of permits and the obtaining of construction financing.

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, corporate guarantees (e.g., self bonds) and letters of credit to secure our financial obligations for reclamation, workers' compensation, coal lease obligations and other obligations as follows as of December 31, 2014:

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Other	Total
	(Dollars in thousands)				
Self bonding	$458,513	$ —	$ —	$ —	$458,513
Surety bonds	177,714	49,364	28,784	8,819	264,681
Letters of credit	3,500	—	92,579	6,945	103,024

In addition, we have agreed to continue to provide surety bonds for certain Magnum obligations, primarily reclamation. The surety bonding amounts are mandated by the state and are not directly related to the estimated cost to reclaim the properties. At December 31, 2014, we had $33.8 million of surety bonds remaining related to Magnum properties.

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:

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.

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, 2014, our balance sheet reflected asset retirement obligation liabilities of $418.1 million, including amounts classified as a current liability. As of December 31, 2014, we estimate the aggregate undiscounted cost of final mine closures to be approximately $980 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 age 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 65% equity and 35% 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 2014 would have been an increase in expense of approximately $1.5 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. In estimating that rate, rates of return on high-quality fixed-income debt instruments are required. We utilize a bond portfolio model that includes bonds that are rated ''AA'' or higher with maturities that match the expected benefit payments under the plan. The impact of lowering the discount rate 0.5% for 2014 would have been an increase in expense of approximately $3.9 million.

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period, which represents the average amount of time before participants vest in their benefits.

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 2014.

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.

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 market pricing.

Our commitments for 2014 and 2015 are as follows:

	2015		2016	
	Tons (in millions)	$ per ton	Tons (in millions)	$ per ton
Powder River Basin				
Committed, Priced	102.5	$13.39	38.4	$14.58
Committed, Unpriced	3.7		15.5	
Appalachia				
Committed, Priced Thermal	5.1	$55.86	2.3	$55.11
Committed, Unpriced Thermal	—		—	
Committed, Priced Metallurgical	3.9	$77.45	0.7	$83.00
Committed, Unpriced Metallurgical	0.1		—	
Other Bituminous				
Committed, Priced	6.0	$33.60	2.8	$34.61
Committed, Unpriced	0.5		—	

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, 2014. The estimated future realization of the value of the trading portfolio is $3.7 million of gains in 2015.

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, 2014, VaR for our coal trading positions that are recorded at fair value through earnings ranged from under $0.1 million to $0.9 million. The linear mean of each daily VaR was $0.4 million. The final VaR at December 31, 2014 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, 2014 VaR for our risk management positions that are recorded at fair value through earnings ranged from $0.1 million to $0.5 million. The linear mean of each daily VaR was $0.2 million. The final VaR at December 31, 2014 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 57 to 67 million gallons of diesel fuel for use in our operations during 2015. 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, 2014, we had purchased heating oil call options for approximately 56 million gallons for the purpose of protecting against substantial increases in price relating to 2015 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, 2014, 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, 2014, of our $5.2 billion principal amount of debt outstanding, approximately $1.9 billion 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, 2014, 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, 2014. 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 the opinion of independent registered public accounting firm and management's report on internal control over financial reporting included on pages F-3 and F-4, respectively, of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 401 of Regulation S-K is included under the caption "Director Qualifications, Diversity and Biographies" in our 2014 Proxy Statement and in Part I of this report under the caption "Executive Officers." The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance Guidelines and Code of Business Conduct," "Nominating Process for Election of Directors" and "Board Meetings and Committees" in our 2015 Proxy Statement. Such information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K is included under the captions "Executive Compensation," "Director Compensation," "Compensation Committee Interlocks and Insider Participation" and "Personnel and Compensation Committee Report" (which is furnished) in our 2015 Proxy Statement and is incorporated herein by reference.

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

The information required by Items 201(d) and 403 of Regulation S-K is included under the captions "Equity Compensation Plan Information," "Security Ownership of Directors and Executive Officers" and "Security Ownership of Certain Beneficial Owners" in our 2015 Proxy Statement and is incorporated herein by reference.

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

The information required by Items 404 and 407(a) of Regulation S-K is included under the caption "Directors and Corporate Governance Practices" in our 2015 Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 9(e) of Schedule 14A is included under the caption "Fees Paid to Auditors" in our 2015 Proxy Statement and is incorporated herein by reference.

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:

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 85 of this report.

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
President and Chief Executive Officer

February 27, 2015

Signatures	Capacity	Date
/s/ JOHN W. EAVES John W. Eaves	President and Chief Executive Officer, Director (Principal Executive Officer)	February 27, 2015
/s/ JOHN T. DREXLER John T. Drexler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2015
/s/ JOHN W. LORSON John W. Lorson	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2015
* Wesley M. Taylor	Chairman of the Board of Directors	February 27, 2015
* David D. Freudenthal	Director	February 27, 2015
* Patricia F. Godley	Director	February 27, 2015
* Paul T. Hanrahan	Director	February 27, 2015

Signatures	Capacity	Date
* Douglas H. Hunt	Director	February 27, 2015
* J. Thomas Jones	Director	February 27, 2015
* Paul A. Lang	Director	February 27, 2015
* George C. Morris III	Director	February 27, 2015
* Theodore D. Sands	Director	February 27, 2015
* Wesley M. Taylor	Director	February 27, 2015
* Peter I. Wold	Director	February 27, 2015

*By /s/ ROBERT G. JONES

Robert G. Jones,
Attorney-in-Fact

Exhibit Index

Exhibit	Description
3.1	Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated herein by reference to Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on May 5, 2006).
3.2	Arch Coal, Inc. Amended and Restated Bylaws, as amended and restated effective as of February 26, 2015 (incorporated herein by reference to Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on February 27, 2015).
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 the registrant's Current Report on Form 8-K filed on August 9, 2010)
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 the registrant's Current Report on Form 8-K filed on August 9, 2010)
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 the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2013).
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 the registrant's Annual Report on Form 10-K for the period ended December 31, 2013).

Exhibit	Description
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 the registrant's Current Report on Form 8-K filed on June 14, 2011).
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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2013).
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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2013).
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 the registrant's Current Report on Form 8-K filed on November 26, 2012).
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 the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2013).
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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2013).

Exhibit	Description
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 the registrant's Current Report on Form 8-K filed on December 17, 2013).
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 the registrant on June 17, 2011).
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 the registrant's Current Report on Form 8-K filed on November 26, 2012).
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 the registrant's Current Report on Form 8-K filed on May 17, 2012).
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 the registrant's Current Report on Form 8-K filed on November 26, 2012).
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 the registrant's Current Report on Form 8-K filed on November 26, 2012).
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 the registrant's Current Report on Form 8-K filed on December 17, 2013).
10.7*	Form of Employment Agreement for Executive Officers of Arch Coal, Inc. (incorporated herein by reference to Exhibit 10.4 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.8	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	Description
10.9	Federal Coal Lease dated as of June 24, 1993 between the U.S. Department of the Interior and Southern Utah Fuel Company (incorporated herein by reference to Exhibit 10.17 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.10	Federal Coal Lease between the U.S. Department of the Interior and Utah Fuel Company (incorporated herein by reference to Exhibit 10.18 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.11	Federal Coal Lease dated as of July 19, 1997 between the U.S. Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10.19 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.12	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).
10.13	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).
10.14	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).
10.15	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).
10.16	Federal Coal Lease dated as of October 1, 1999 between the U.S. Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).
10.17	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).
10.18	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).
10.19	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	Description
10.20	State Coal Lease executed October 1, 2004 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company and Arch Coal, Inc., as lessees, covering a tract of land located in Seiever County, Utah (incorporated by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.21	State Coal Lease executed September 1, 2000 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Canyon Fuel Company, LLC, as lessee, for lands located in Carbon County, Utah (incorporated by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.22	Federal Coal Lease executed September 1, 1996 by and between the Bureau of Land Management, as lessor, and Canyon Fuel Company, LLC, as lessee, covering a tract of land known as "The North Lease" in Carbon County, Utah (incorporated by reference to Exhibit 10.22 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.23	State Coal Lease executed January 18, 2008 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company, as lessee, for lands located in Emery County, Utah (incorporated by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
10.24*	Form of Indemnity Agreement between Arch Coal, Inc. and Indemnitee (as defined therein) (incorporated herein by reference to Exhibit 10.15 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.25*	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).
10.26*	Arch Coal, Inc. Deferred Compensation Plan.
10.27*	Arch Coal, Inc. Omnibus Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q filed on May 8, 2013).
10.28*	Arch Mineral Corporation 1996 ERISA Forfeiture Plan (incorporated herein by reference to Exhibit 10.20 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.29*	Arch Coal, Inc. Outside Directors' Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.4 of the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.30*	Arch Coal, Inc. Supplemental Retirement Plan (as amended on December 5, 2008) (incorporated herein by reference to Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.31*	Form of Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
10.32*	Form of Non-Qualified Stock Option Agreement (for stock options granted prior to February 21, 2008) (incorporated herein by reference to Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).

Exhibit	Description
10.33*	Form of 2008 Restricted Stock Unit Contract for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.34*	Form of 2008 Non-Qualified Stock Option Agreement for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.35*	Form of Non-Qualified Stock Option Agreement (for stock options granted on or after February 21, 2008) (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.36*	Form of Non-Qualified Stock Option Agreement (incorporated herein by reference to Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2013).
10.37*	Form of Performance Unit Contract (incorporated herein by reference to Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2013).
10.38*	Form of 2011 Non-Qualified Stock Option Agreement (incorporated herein by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.39*	Form of 2011 Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.40*	Form of 2011 Restricted Stock Unit Contract for Non-Employee Directors (incorporated herein by reference to Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.41*	Form of 2011 Performance Unit Contract (incorporated herein by reference to Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.42*	Form of Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2013).
10.43*	Form of Restricted Stock Unit Contract for Non-Employee Directors (incorporated herein by reference to Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2013).
10.44*	Form of Director Indemnity Agreement (incorporated herein by reference to Exhibit 10.40 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
10.45*	Form of Performance Shares Contract (incorporated by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2014).
10.46	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 from 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 the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010).

Exhibit	Description
10.47	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 the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
10.48	Second Amendment to Amended and Restated Receivables Purchase Agreement dated June 15, 2011 (incorporated by reference to Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2011).
10.49	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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.50	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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.51	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 the registrant's Annual Report on Form 10-K for the period ended December 31, 2012).
10.52	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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2013).
10.53	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 the registrant's Annual Report on Form 10-K for the year ended December 31, 2013).
10.54	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.
10.55	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.
12.1	Computation of ratio of earnings to combined fixed charges and preference dividends.
21.1	Subsidiaries of the registrant.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Weir International, Inc.
24.1	Power of Attorney.
31.1	Rule 13a-14(a)/15d-14(a) Certification of John W. Eaves.
31.2	Rule 13a-14(a)/15d-14(a) Certification of John T. Drexler.

Exhibit	Description
32.1	Section 1350 Certification of John W. Eaves.
32.2	Section 1350 Certification of John T. Drexler.
95	Mine Safety Disclosure Exhibit.
101	Interactive Data File (Form 10-K for the year ended December 31, 2014 filed in XBRL). The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed."

* Denotes management contract or compensatory plan arrangements.

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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. and subsidiaries at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Arch Coal, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

St. Louis, Missouri
February 27, 2015

Report of Independent Registered Public Accounting Firm

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

We have audited Arch Coal, Inc. and subsidiaries' (the Company's) internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Arch Coal, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Arch Coal, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Arch Coal, Inc. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014, and our report dated February 27, 2015, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 27, 2015

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, 2014 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, 2014.

The Company's independent registered public accounting firm, Ernst & Young LLP, has issued an audit opinion on the Company's internal control over financial reporting as of December 31, 2014.

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

	Year Ended December 31,		
	2014	2013	2012
Revenues	$2,937,119	$ 3,014,357	$ 3,768,126
Costs, expenses and other operating			
Cost of sales (exclusive of items shown separately below)	2,566,193	2,663,136	3,155,099
Depreciation, depletion and amortization	418,748	426,442	492,211
Amortization of acquired sales contracts, net	(13,187)	(9,457)	(25,189)
Change in fair value of coal derivatives and coal trading activities, net	(3,686)	7,845	(16,590)
Asset impairment and mine closure costs	24,113	220,879	539,182
Goodwill impairment	—	265,423	330,680
Contract settlement resulting from Patriot Coal bankruptcy	—	—	58,335
Reduction in accrual related to acquired litigation	—	—	(79,532)
Selling, general and administrative expenses	114,223	133,448	134,299
Other operating income, net	(19,754)	(30,218)	(63,357)
	3,086,650	3,677,498	4,525,138
Loss from operations	(149,531)	(663,141)	(757,012)
Interest expense, net			
Interest expense	(390,946)	(381,267)	(317,615)
Interest and investment income	7,758	6,603	5,473
	(383,188)	(374,664)	(312,142)
Nonoperating expense			
Net loss resulting from early retirement and refinancing of debt	—	(42,921)	(23,668)
Loss from continuing operations before income taxes	(532,719)	(1,080,726)	(1,092,822)
Provision for (benefit from) income taxes	25,634	(335,498)	(353,907)
Loss from continuing operations	(558,353)	(745,228)	(738,915)
Income from discontinued operations, including gain on sale—net of tax	—	103,396	55,228
Net loss	(558,353)	(641,832)	(683,687)
Less: Net income attributable to noncontrolling interest	—	—	(268)
Net loss attributable to Arch Coal, Inc.	$ (558,353)	$ (641,832)	$ (683,955)
Losses per common share			
Basic and diluted LPS—Loss from continuing operations	$ (2.63)	$ (3.52)	$ (3.50)
Basic and diluted LPS—Net loss	$ (2.63)	$ (3.03)	$ (3.24)
Basic and diluted weighted average shares outstanding	212,221	212,098	211,381
Dividends declared per common share	$ 0.01	$ 0.12	$ 0.20

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)

	Year Ended December 31,		
	2014	2013	2012
Net loss	$(558,353)	$(641,832)	$(683,687)
Derivative instruments			
Comprehensive income (loss) before tax	3,102	(2,626)	10,894
Income tax benefit (provision)	(1,117)	947	(3,921)
	1,985	(1,679)	6,973
Pension, postretirement and other post-employment benefits			
Comprehensive income (loss) before tax	(44,143)	77,201	(21,291)
Income tax benefit (provision)	15,891	(27,803)	7,686
	(28,252)	49,398	(13,605)
Available-for-sale securities			
Comprehensive income (loss) before tax	(12,788)	10,190	(3,000)
Income tax benefit (provision)	4,604	(3,710)	1,080
	(8,184)	6,480	(1,920)
Total other comprehensive income (loss)	(34,451)	54,199	(8,552)
Total comprehensive loss	$(592,804)	$(587,633)	$(692,239)

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)

	December 31, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$ 734,231	$ 911,099
Short term investments	248,954	248,414
Trade accounts receivable	211,506	198,020
Other receivables	20,511	31,553
Inventories	190,253	264,161
Prepaid royalties	11,118	8,083
Deferred income taxes	52,728	49,144
Coal derivative assets	13,257	14,851
Other current assets	60,193	56,746
Total current assets	1,542,751	1,782,071
Property, plant and equipment		
Coal lands and mineral rights	6,040,656	5,991,719
Plant and equipment	2,935,381	2,882,486
Deferred mine development	891,649	979,270
	9,867,686	9,853,475
Less accumulated depreciation, depletion and amortization	(3,414,228)	(3,119,189)
Property, plant and equipment, net	6,453,458	6,734,286
Other assets		
Prepaid royalties	66,806	87,577
Equity investments	235,842	221,456
Other noncurrent assets	130,866	164,803
Total other assets	433,514	473,836
Total assets	$ 8,429,723	$ 8,990,193
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 180,113	$ 176,142
Accrued expenses and other current liabilities	302,396	278,587
Current maturities of debt	36,885	33,493
Total current liabilities	519,394	488,222
Long-term debt	5,123,485	5,118,002
Asset retirement obligations	398,896	402,713
Accrued pension benefits	16,260	7,111
Accrued postretirement benefits other than pension	32,668	39,255
Accrued workers' compensation	94,291	78,062
Deferred income taxes	422,809	413,546
Other noncurrent liabilities	153,766	190,033
Total liabilities	6,761,569	6,736,944
Stockholders' equity		
Common stock, $0.01 par value, authorized 260,000 shares, issued 213,791 and 213,792 shares at December 31, 2014 and 2013, respectively	2,141	2,141
Paid-in capital	3,048,460	3,038,613
Treasury stock, at cost	(53,863)	(53,848)
Accumulated deficit	(1,331,825)	(771,349)
Accumulated other comprehensive income	3,241	37,692
Total stockholders' equity	1,668,154	2,253,249
Total liabilities and stockholders' equity	$ 8,429,723	$ 8,990,193

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

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

	Year Ended December 31,		
	2014	2013	2012
Operating activities			
Net income (loss)	$(558,353)	$(641,832)	$ (683,687)
Adjustments to reconcile net loss to cash provided by operating activities:			
Depreciation, depletion and amortization	418,748	447,704	525,508
Amortization of acquired sales contracts, net	(13,187)	(9,457)	(25,189)
Prepaid royalties expensed	9,698	13,706	22,650
Deferred income taxes	25,152	(263,099)	(336,036)
Employee stock-based compensation expense	9,847	11,790	11,822
Gains on disposals and divestitures	(27,512)	(120,321)	—
Asset impairment and noncash mine closure costs	16,868	220,879	531,234
Goodwill impairment	—	265,423	330,680
Amortization of premiums on debt securities held	—	3,680	—
Amortization relating to financing activities	17,363	24,789	20,238
Net loss resulting from early retirement of debt and financing activities	—	42,921	23,668
Changes in:			
Receivables	(8,991)	62,881	113,531
Inventories	41,548	44,635	9,468
Coal derivative assets and liabilities	5,449	3,606	(13,158)
Accounts payable, accrued expenses and other current liabilities	41,680	(78,126)	(170,430)
Asset retirement obligations	18,288	17,432	(42,531)
Pension, postretirement and other postemployment benefits	(25,347)	7,284	12,319
Other	(4,833)	1,847	2,717
Cash provided by (used in) operating activities	(33,582)	55,742	332,804
Investing activities			
Capital expenditures	(147,286)	(296,984)	(395,225)
Minimum royalty payments	(7,317)	(14,947)	(13,269)
Proceeds from sale-leaseback transactions	—	34,919	—
Proceeds from disposals and divestitures	62,358	433,453	22,825
Purchases of short term investments	(211,929)	(213,726)	(236,862)
Proceeds from sales of short term investments	205,611	194,537	1,754
Proceeds from sale of investments in equity securities	9,464	—	—
Investments in and advances to affiliates, net	(16,657)	(15,260)	(17,758)
Purchase of noncontrolling interest	—	—	(17,500)
Change in restricted cash	—	3,453	6,869
Cash provided by (used in) investing activities	(105,756)	125,445	(649,166)
Financing activities			
Proceeds from term loan	—	294,000	1,633,500
Proceeds from issuance of senior notes	—	350,000	359,753
Payments to retire debt	(300)	(628,660)	(452,934)
Payments on term loan	(19,500)	(17,250)	(7,625)
Net decrease in borrowings under lines of credit	—	—	(481,300)
Net payments on other debt	(5,395)	(6,836)	(682)
Debt financing costs	(4,519)	(20,489)	(50,568)
Dividends paid	(2,123)	(25,475)	(42,440)
Proceeds from exercise of options under incentive plans	—	—	5,131
Other	(5,693)	—	—
Cash provided by (used in) financing activities	(37,530)	(54,710)	962,835
Increase (decrease) in cash and cash equivalents	(176,868)	126,477	646,473
Cash and cash equivalents, beginning of period	911,099	784,622	138,149
Cash and cash equivalents, end of period	$ 734,231	$ 911,099	$ 784,622
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid during the year for interest	$ 361,727	$ 380,389	$ 310,241
Cash refunded during the year for income taxes, net	$ (4,896)	$ (18,741)	$ (28,057)

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

Arch Coal, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity
Three Years Ended December 31, 2014

	Common Stock	Paid-In Capital	Treasury Stock, at Cost	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(In thousands, except per share data)					
BALANCE AT JANUARY 1, 2012	$2,136	$3,015,349	$(53,848)	$ 622,353	$ (7,950)	$3,578,040
Total comprehensive loss	—	—	—	(683,955)	(8,557)	(692,512)
Dividends on common shares ($0.20 per share)	—	—	—	(42,440)	—	(42,440)
Redemption of noncontrolling interest	—	(5,474)	—	—	—	(5,474)
Issuance of 49 shares of common stock under the stock incentive plan—restricted stock and restricted stock units, net of forfeitures	0	0	—	—	—	—
Issuance of 526 shares of common stock under the stock incentive plan—stock options including income tax benefits	5	5,126	—	—	—	5,131
Employee stock-based compensation expense	—	11,822	—	—	—	11,822
BALANCE AT DECEMBER 31, 2012	2,141	3,026,823	(53,848)	(104,042)	(16,507)	2,854,567
Total comprehensive income (loss)	—	—	—	(641,832)	54,199	(587,633)
Dividends on common shares ($0.12 per share)	—	—	—	(25,475)	—	(25,475)
Issuance of 39 shares of common stock under the stock incentive plan—restricted stock and restricted stock units, net of forfeitures	0	0	—	—	—	—
Employee stock-based compensation expense	—	11,790	—	—	—	11,790
BALANCE AT DECEMBER 31, 2013	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)	—	—	—	(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

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"). 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, Maryland, Virginia, Illinois, Wyoming and Colorado. All subsidiaries are wholly-owned. Intercompany transactions and accounts have been eliminated in consolidation.

The Company completed the sale of Canyon Fuel Company, LLC (Canyon Fuel) on August 16, 2013. The results of these mining complexes have been segregated from continuing operations and are reflected, net of tax, as discontinued operations in the consolidated statements of operations for all periods presented. See further discussion in Note 3, "Divestitures".

In response to weak coal markets, the Company has idled or closed mines in the Appalachia region and sold other non-core operating subsidiaries and assets. The results from these operations and gains or losses on the disposal are reflected in income from continuing operations in the consolidated statements of operations. See further discussion in Note 5, "Impairment Charges and Mine Closure Costs".

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 Pronouncements

There are no accounting pronouncements whose adoption had, or is expected to have, a material impact on the Company's consolidated financial statements.

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.

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 income, net" in the consolidated statements of operations. Information about investment activity is provided in Note 9, "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.

Acquired Sales Contracts

Coal supply agreements (sales contracts) 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, "Acquired Sales Contracts" for further information related to the Company's acquired 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 are recorded at cost. Interest costs incurred during the construction period for major asset additions are capitalized. We capitalized $15.9 million and $15.6 million of interest costs during the years ended December 31, 2013 and 2012, 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 5 to 32 years. The useful lives of buildings and leasehold improvements generally range from 10 to 30 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 $4.7 billion and $4.8 billion at December 31, 2014 and 2013, 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.

Future lease bonus payments total $75.4 million in 2015 and $60.0 million in 2016

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, ''Impairment Charges and Mine Closure Costs''.

Goodwill

In a business combination, goodwill represents the excess of the purchase price over the fair value assigned to the net tangible and identifiable intangible assets acquired. The Company tests goodwill for impairment annually as of the beginning of the fourth quarter, or when circumstances indicate a possible impairment may exist. If the results of the testing indicate that the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the fair value of goodwill must be calculated. An impairment loss generally would be recognized when the carrying amount of goodwill exceeds the implied fair value of goodwill, determined by subtracting the fair value of the other assets and liabilities associated with the reporting unit from the total fair value of the reporting unit. The fair value of a reporting unit is determined using a discounted cash flow (''DCF'') technique. A number of significant assumptions and estimates are involved in the application of the DCF analysis to forecast operating cash flows, including the discount rate, projections of production volumes, quality and costs to produce; projections of sales volumes by market (e.g., thermal versus metallurgical); and projections of market prices. See additional discussion in Note 6, ''Goodwill.''

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. The unamortized balance of deferred financing costs was $89.1 million and $99.2 million at December 31, 2014 and 2013, respectively. Amounts classified as current were $25.5 million and $19.7 million at December 31, 2014 and 2013, respectively. Current amounts are recorded in ''Other current assets'' and noncurrent amounts are recorded in ''Other noncurrent assets'' 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 Income and Expenses

Other operating 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 (Note 3); 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 years ended December 31, 2014, 2013 and 2012.

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 Values 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. Benefits are generally based on the employee's age and compensation. 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. 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 is determined using a Black-Scholes option pricing model. 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.''

Accounting Standards Issued

In May 2014, the FASB issued comprehensive authoritative guidance for the recognition and presentation of revenue from contracts with customers. The revenue recognition model is based on changes in contract assets (right to receive consideration) and liabilities (obligations to provide a good or perform a service). The guidance also requires comprehensive quantitative and qualitative disclosures intended to enable financial statement users to understand the nature, timing and uncertainty of revenue and the related cash flows. This guidance will be effective for the Company in the first quarter of 2017, with early adoption not permitted. The Company is currently assessing the impact the guidance will have upon adoption, but expects no significant changes to its existing revenue recognition policies.

In August 2014, the FASB issued guidance requiring management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued and requires disclosures to describe the principal conditions or events that raise substantial doubt and management's evaluation and plans to alleviate such doubt. If the doubt is not alleviated by management's plans, the notes to the financial statements must include a statement that the doubt exists. This requirement is effective for annual and interim periods starting with the period ending December 31, 2016.

3. Divestitures

During 2014, the Company entered into agreements to sell various non-core operations, including operating and idled thermal coal complexes in Kentucky and the Company's highwall manufacturing subsidiary. The Company received $46.7 million in cash and recognized a net pre-tax gain of $17.8 million from these divestitures, reflected in ''other operating income, net'' in the condensed consolidated statement of operations.

The following table summarizes the assets and liabilities of these divested operations reflected in the December 31, 2013 consolidated balance sheet (in thousands):

Inventories	$33,730
Other current assets	2,060
Net property, plant & equipment	35,560
Other noncurrent assets	190
Accounts payable and accrued expenses	10,599
Other noncurrent liabilities	38,340

As part of a strategy to divest non-core thermal coal assets, the Company entered into a definitive agreement on June 27, 2013 to sell Canyon Fuel, to Bowie Resources, LLC. Canyon Fuel operated two longwall mining complexes and a continuous miner operation in Utah. The sale was completed on August 16, 2013, for $422.7 million in cash, including adjustments to the purchase price to finalize working capital.

The following table summarizes the results of discontinued operations through the date of disposition:

	Year Ended December 31,	
	2013	2012
	(In thousands)	
Total Revenues	$219,002	$390,912
Income from discontinued operations before income taxes	$ 32,167	$ 75,418
Gain on sale	120,321	—
Less: income tax expense	49,092	20,190
Income from discontinued operations, including gain on sale—net of tax	$103,396	$ 55,228
Basic earnings per common share from discontinued operations	$ 0.49	$ 0.26
Diluted earnings per common share from discontinued operations	$ 0.49	$ 0.26

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)			
Balance at January 1, 2013	$ 2,244	$(18,286)	$ (465)	$(16,507)
Unrealized gains	168	48,482	5,935	54,585
Amounts reclassified from accumulated other comprehensive income (loss)	(1,847)	916	545	(386)
Balance at December 31, 2013	565	31,112	6,015	37,692
Unrealized gains (losses)	3,677	(22,516)	(5,727)	(24,566)
Amounts reclassified from accumulated other comprehensive income (loss)	(1,692)	(5,736)	(2,457)	(9,885)
Balance at December 31, 2014	$ 2,550	$ 2,860	$(2,169)	$ 3,241

The following amounts were reclassified out of accumulated other comprehensive income (loss) during the years ended December 31, 2014 and 2013, respectively:

Details about accumulated other comprehensive income components	Reclassifications 2014	Reclassifications 2013	Line Item in the Consolidated Statement of Operations
	(in thousands)		
Derivative instruments	$ 2,643	$ 2,886	Revenues
	(951)	(1,039)	Provision for (benefit from) income taxes
	$ 1,692	$ 1,847	Net of tax
Pension, postretirement and other post-employment benefits			
Amortization of prior service credits	$11,760[1]	$ 13,705	
Amortization of net actuarial gains (losses)	(2,797)[1]	(15,136)	
	8,963	(1,431)	Total before tax
	(3,227)	515	Provision for (benefit from) income taxes
	$ 5,736	$ (916)	Net of tax
Available-for-sale securities	$ 3,838[2]	$ (852)	Interest and investment income
	(1,381)	307	Provision for (benefit from) income taxes
	$ 2,457	$ (545)	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 discussions describe the costs reflected on the line "Asset impairment and mine closure costs" in the consolidated statements of operations.

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.

During the Company's annual budgeting process for 2015, a review of our 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 for $15.4 million of the remaining $48.0 million balance that would not be recouped.

As a result of the weak thermal coal markets in Appalachia, the Company assessed in the third quarter of 2013 whether the carrying values of certain assets were recoverable through future cash flows. The Company determined that the carrying amounts of certain assets associated with the Hazard mining complex in Kentucky and the Company's ADDCAR subsidiary, which manufactures and sells its patented highwall mining system, could not be recovered through future cash flows expected to be generated from use of the assets and their ultimate disposal.

The assets' fair values were determined based on projections of cash flows to be generated from use of the assets and their ultimate disposal including estimates relating to market demand, coal prices, production costs and mine plans, and recovery value of the assets. An impairment charge of $142.8 million was recognized to adjust the carrying value of the assets to their fair value of $71.3 million.

During 2013, the Company also recognized other-than-temporary impairment charges related to equity method investments. See further discussion in Note 9, "Equity Method Investments and Membership Interests in Joint Ventures."

In 2012, the closure and idling of mines in Appalachia discussed in Note 1, "Basis of Presentation" resulted in closure costs and related impairment charges as follows:

	In millions
Parts and supplies inventory writedown	$ 2.6
Impairment of property, plant and equipment	95.6
Impairment of coal properties and deferred development costs	403.3
Royalty obligations	11.5
Employee termination benefits	12.3
Pension, postretirement and occupational disease curtailment gain, net	(1.8)
	$523.5

In 2012, the value of an acquired sales contract was also determined to be impaired, see further discussion in Note 10, "Acquired Sales Contracts" for further discussion.

6. Goodwill

Changes in the carrying value of goodwill for the three years ended December 31, 2014 are as follows:

	(In thousands)
Balance at January 1, 2012	$ 596,103
Impairment	(330,680)
Balance at December 31, 2012	265,423
Impairment	(265,423)
Balance at December 31, 2013	$ —

During the second quarter of 2012, the Company concluded the fair value of the Company's goodwill could be less than its carrying value, based on a significant drop in the Company's stock price combined with continuing weak demand for thermal coal. Accordingly, the Company performed the first step of the two-step goodwill impairment test as of June 30, 2012. The value of the Company's Black Thunder reporting unit in the Powder River Basin, where $115.8 million of goodwill had been allocated, was sensitive to market demand for thermal coal and the further weakening in thermal coal markets had significantly impacted the projected demand for and pricing of coal produced at Black Thunder. In step one of the goodwill impairment testing, the fair value of the Black Thunder reporting unit did not exceed its carrying value, primarily due to the impact of lower demand on near term sales volumes and pricing. The Company recorded an impairment charge for the entire $115.8 million carrying value of Black Thunder's goodwill in 2012.

During 2012, metallurgical prices fell substantially from the peaks reached during 2011, when the reporting units were acquired with the Company's purchase of ICG. Because the goodwill amounts allocated to certain reporting units in the Company's Appalachia segment acquired with the ICG acquisition were sensitive to volatility in the demand for metallurgical coal, the fair values of two of these reporting units fell below their carrying value. The allocated goodwill of $214.9 million for those reporting units was determined to be fully impaired, based on the discounted cash flows used in the ICG acquisition valuation, adjusted for current market conditions and estimates of production levels.

The Company performed its annual impairment testing as of October 1, 2013 on the two remaining Appalachia reporting units with goodwill balances, the Leer mining complex and an undeveloped property adjacent to it. The fair value of these two reporting units are sensitive to the volatility in the demand for and pricing of metallurgical coal, and continuing weakness in the metallurgical coal markets resulted in a reassessment of key marketing and operating assumptions during the Company's annual budgeting process. As a result, the book values of the reporting units exceeded their fair values after the first step of the goodwill impairment tests. It was also determined that the goodwill had no fair value, and the Company recognized an impairment loss for the remaining reporting units totaling $265.4 million.

7. Inventories

Inventories consist of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
Coal	$ 71,901	$117,531
Repair parts and supplies	118,352	137,497
Work-in-process	—	9,133
	$190,253	$264,161

The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $6.6 million at December 31, 2014 and $8.4 million at December 31, 2013.

8. Investments in Available-for-Sale Securities

The Company has invested 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:

	December 31, 2014					
					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	$253,590	$ —	$(4,636)	$248,954	$248,954	$ —
Equity securities	3,910	4,125	(2,890)	5,145	—	5,145
Total Investments	$257,500	$4,125	$(7,526)	$254,099	$248,954	$5,145

	December 31, 2013					
					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	$ 65,002	$ 11	$ (75)	$ 64,938	$ 64,938	$ —
Corporate notes and bonds	184,773	7	(1,304)	183,476	183,476	—
Equity securities	5,271	13,660	(2,902)	16,029	—	16,029
Total Investments	$255,046	$13,678	$(4,281)	$264,443	$248,414	$16,029

The aggregate fair value of investments with unrealized losses that had been owned for less than a year was $163.0 million and $164.3 million at December 31, 2014 and 2013, respectively. The aggregate fair value of investments with unrealized losses that have been owned for over a year was $86.1 million and $48.7 million at December 31, 2014 and 2013, respectively.

The debt securities outstanding at December 31, 2014 have maturity dates ranging from the first quarter of 2015 through the first quarter of 2016. 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. Certain of the Company's investments are in development stage companies whose success depends on factors including the receipt of permits and other regulatory environmental issues, the ability of the investee companies to raise additional funds in financial markets that can be volatile, and other key business factors, any of which may impact the Company's ability to recover its investment.

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

Investee	Knight Hawk	DTA	Millennium	Tongue River	DKRW	Tenaska	Other	Total
Balance at January 1, 2012	$135,225	$16,086	$26,324	$12,989	$ 19,715	$ 15,266	$ —	$225,605
Investments in affiliates	—	—	—	—	—	—	—	—
Advances to (distributions from) affiliates, net	(7,151)	4,335	8,798	1,708	—	—	—	7,690
Equity in comprehensive income (loss)	20,989	(4,959)	(2,908)	—	(4,200)	(2)	—	8,920
Balance at December 31, 2012	149,063	15,462	32,214	14,697	15,515	15,264	—	242,215
Advances to (distributions from) affiliates, net	(13,536)	3,644	6,476	4,004	—	—	200	788
Equity in comprehensive income (loss)	17,279	(4,969)	(2,796)	(282)	(1,832)	—	—	7,400
Impairment of equity investment	—	—	—	—	(13,683)	(15,264)	—	(28,947)
Balance at December 31, 2013	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
Balance at December 31, 2014	$158,477	$13,738	$40,223	$20,740	$ —	$ —	$ 2,664	$235,842

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 holds 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. Additional future purchase consideration is due upon the completion of certain project milestones. 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. The Company will control 38% of the terminal's throughput and storage capacity, in order to facilitate export shipments of coal off the west coast of the United States.

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 has 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.

The Company holds a 24% equity interest in DKRW Advanced Fuels LLC ("DKRW"), who had entered into an Engineering, Procurement and Construction Agreement with a Chinese company to construct and commission the Medicine Bow coal-to-liquids facility. However, as the project did not progress to the next stage of development, the Company recorded an other-than-temporary impairment charge of $57.7 million in the third quarter of 2013, representing the Company's equity investment of $13.7 million and an outstanding $44.0 million loan receivable balance. The impairment charges are included on the line "Asset impairment and mine closure costs" in the consolidated statement of operations.

During the second quarter of 2013, Tenaska Trailblazer Partners, LLC ("Tenaska") announced that it was discontinuing its development plans for the Trailblazer Energy Center in Texas. As a result, the Company recorded a $20.5 million impairment charge, which consisted of its 35% equity investment of $15.3 million and a $5.2 million receivable balance related to advances for development work. The impairment charges are included on the line "Asset impairment and mine closure costs" in the consolidated statement of operations.

The Company may be required to make future contingent payments of up to $58.5 million related to development financing for certain of its equity investees. The Company's obligation to make these payments, as well as the timing of any payments required, is contingent upon the achievement of project development milestones, which can be affected by the factors named above.

10. Acquired Sales Contracts

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

	December 31, 2014			December 31, 2013		
	Assets	Liabilities	Net Total	Assets	Liabilities	Net Total
	(In thousands)			(In thousands)		
Acquired fair value	$ 131,299	$ 166,697		$ 131,819	$ 166,697	
Accumulated amortization	(130,363)	(134,988)		(129,449)	(120,367)	
Total	$ 936	$ 31,709	$(30,773)	$ 2,370	$ 46,330	$(43,960)
Balance Sheet classification:						
Other current	$ 462	$ 12,453		$ 1,324	$ 14,373	
Other noncurrent	$ 474	$ 19,256		$ 1,046	$ 31,957	

In 2012, the Company recognized an impairment loss of $15.7 million to write off a contract acquired with the ICG acquisition with an original acquired fair value of $17.5 million.

The Company anticipates amortization of acquired sales contracts, based upon expected shipments in the next five years, to be income of approximately $12.2 million in 2015, $7.2 million in 2016, $3.6 million in 2017, and $3.6 million in 2018 and $4.1 million in 2019.

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 57 to 67 million gallons of diesel fuel for use in its operations during 2015. 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, 2014, the Company had heating oil call options for approximately 56 million gallons at an average strike price of $3.13.

The Company has also at times purchased heating oil call options to manage the price risk associated with fuel surcharges on its barge and rail shipments, which cover increases in diesel fuel prices for the respective carriers. These positions reduce the Company's risk of cash flow fluctuations related to these surcharges but the positions are not accounted for as hedges. The Company had no positions outstanding at December 31, 2014.

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, 2014, the Company held derivatives for risk management purposes that are expected to settle in the following years:

(Tons in thousands)	2015	2016	Total
Coal sales	4,522	280	4,802
Coal purchases	2,134	—	2,134

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 $3.7 million in the trading portfolio are expected to be realized in 2015.

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:

Fair Value of Derivatives (In thousands)	December 31, 2014 Asset Derivative	December 31, 2014 Liability Derivative		December 31, 2013 Asset Derivative	December 31, 2013 Liability Derivative	
Derivatives Designated as Hedging Instruments						
Coal	$ 6,535	$ (2,492)		$ 909	$ (26)	
Derivatives Not Designated as Hedging Instruments						
Heating oil—diesel purchases	300	—		4,681	—	
Heating oil—fuel surcharges	—	—		422	—	
Coal held for trading purposes, exchange traded swaps and futures	96,898	(93,272)		55,327	(45,763)	
Coal—risk management	8,510	(3,688)		6,342	(1,950)	
Total	105,708	(96,960)		66,772	(47,713)	
Total derivatives	112,243	(99,452)		67,681	(47,739)	
Effect of counterparty netting	(98,686)	98,686		(47,727)	47,727	
Net derivatives as classified in the balance sheets	$ 13,557	$ (766)	$12,791	$ 19,954	$ (12)	$19,942

		December 31, 2014	December 31, 2013
Net derivatives as reflected on the balance sheets			
Heating oil	Other current assets	$ 300	$ 5,103
Coal	Coal derivative assets	13,257	14,851
	Accrued expenses and other current liabilities	(766)	(12)
		$12,791	$19,942

The Company had a current liability for the obligation to return cash collateral of $2.4 million and a current asset for the right to reclaim cash collateral of $2.2 million at December 31, 2014 and 2013, respectively. These amounts are not included with the derivatives presented in the table above and are included in ''other current liabilities'' and ''other current assets'', respectively, 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)

	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion)			Gains (Losses) Reclassified from Other Comprehensive Income into Income (Effective Portion)		
For the year ended December 31	2014	2013	2012	2014	2013	2012
Coal sales[1]	$10,842	$(338)	$7,690	$ 5,336	$3,664	$2,675
Coal purchases[2]	(5,097)	526	(2,440)	(2,693)	(683)	—
	$ 5,745	$ 188	$5,250	$ 2,643	$2,981	$2,675

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 years ended December 31, 2014, 2013 and 2012.

Derivatives Not Designated as Hedging Instruments (in thousands)

	Gain (Loss) Recognized		
For the year ended December 31	2014	2013	2012
Coal—unrealized[3]	$ 430	$(12,700)	$ 8,272
Coal—realized[4]	$ 5,956	$ 32,534	$ 43,990
Heating oil—diesel purchases[4]	$(7,848)	$ (9,791)	$(22,281)
Heating oil—fuel surcharges[4]	$ (405)	$ (947)	$ (2,209)

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

During the first quarter of 2012, the Company determined that the effectiveness of heating oil options as a hedge for diesel fuel purchases could not be established as of December 31, 2011. As a result, the amount remaining in accumulated other comprehensive income of $8.2 million was recorded in the "Other operating income, net" line in the consolidated statement of operations, or $5.2 million, net of income taxes.

The Company recognized net unrealized and realized gains of $3.2 million, $4.9 million, and $8.3 million during the years ended December 31, 2014, 2013 and 2012, 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, 2014, gains on derivative contracts designated as hedge instruments in cash flow hedges of approximately $4.0 million are expected to be reclassified from other comprehensive income into earnings during the next twelve months.

12. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following:

	December 31, 2014	December 31, 2013
	(In thousands)	
Payroll and employee benefits	$ 73,362	$ 67,621
Taxes other than income taxes	114,598	114,664
Interest	30,384	18,528
Acquired sales contracts	12,453	14,373
Workers' compensation	16,714	12,434
Asset retirement obligations	19,222	24,940
Other	35,663	26,027
	$302,396	$278,587

13. Debt and Financing Arrangements

	December 31, 2014	December 31, 2013
	(In thousands)	
Term loan due 2018 ($1.9 billion and $1.93 billion face value, respectively)	$1,890,846	$1,906,975
7.00% senior notes due 2019 at par	1,000,000	1,000,000
8.00% senior secured notes due 2019 at par	350,000	350,000
9.875% senior notes ($375.0 million face value) due 2019	363,493	362,358
7.25% senior notes due 2020 at par	500,000	500,000
7.25% senior notes due 2021 at par	1,000,000	1,000,000
Other	56,031	32,162
	5,160,370	5,151,495
Less current maturities of debt	36,885	33,493
Long-term debt	$5,123,485	$5,118,002

Credit Facilities

Under the Company's senior secured revolving credit facility, borrowings of up to $250 million bear interest at a floating rate based on LIBOR determined by reference to the Company's leverage ratio, as calculated in accordance with the underlying amended credit agreement. The credit agreement, which also governs its term loan due 2018, was amended in 2013 to decrease the available capacity of the senior secured revolving credit facility from $350 million to the current level. The credit facility expires on June 14, 2016 and is secured by assets pledged by the Company, including equity interests in wholly-owned subsidiaries, certain real property interests, accounts receivable and inventory of the Company. Commitment fees of 0.50% to 0.75% per annum are payable on the average unused daily balance of the revolving credit facility.

The Company is also party to an accounts receivable securitization program under which eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. The entity through which these receivables are sold is consolidated into the Company's financial statements. The Company may borrow and draw letters of credit against the facility, and pays facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit). The total aggregate borrowings and letters of credit are limited by eligible accounts receivable, as defined under the terms of the credit facility agreement. The credit agreement expires on December 8, 2017, unless the Company's minimum liquidity, including liquid assets, falls below $550 million.

At December 31, 2014, the available borrowing capacity under the Company's lines of credit was approximately $215.1 million.

Term Loan

On May 16, 2012, the Company borrowed $1.4 billion under a secured term loan facility, issued at a 1% discount. The proceeds from the term loan were used to retire all outstanding borrowings under the revolving credit facility and the outstanding $450.0 million principal amount of 6.75% Senior Notes due 2013 issued by Arch Western Finance, LLC, the Company's indirect subsidiary. On November 21, 2012, the Company borrowed an incremental $250.0 million on the term loan facility at a 1% discount at the same rate as the initial borrowing. On December 17, 2013 the credit facility amendment increased the maximum amount of term loans allowed under the facility, and the Company borrowed an incremental $300.0 million aggregate principal amount at 98% of the face amount.

The term loan contains no financial maintenance covenants, is prepayable, and is secured by the same assets as borrowings under the revolving credit facility. Quarterly principal payments of $3.5 million began in September 2012, increased to $4.125 million per quarter as a result of the incremental borrowing in November, 2012, and increased further to $4.875 million with the December 17, 2013 borrowing. A balloon payment of $1.8 billion is due in May, 2018. Interest is payable at a rate that is equal to a base of the greater of a LIBOR-based rate and 1.25%, plus 500 basis points.

2019 9.875% Notes

On November 21, 2012, the Company issued $375.0 million aggregate principal amount of 9.875% senior unsecured notes due 2019 (the "2019 9.875% Notes") at an issue price of 95.934% of the face amount. Interest is payable on the 2019 9.875% Notes annually on June 15 and December 15. The Company may redeem some or all of the notes at prices that are reflected as a percentage of the principal amount, as follows: 104.938% commencing December 15, 2016; 102.469% commencing December 15, 2017; and 100% on or after December 15, 2018.

The unsecured senior notes are guaranteed by substantially all of the Company's subsidiaries, except for Arch Receivable Company, LLC, which is the conduit for the accounts receivable securitization program, and the Company's subsidiaries outside the U.S.

2019 Secured Notes

On December 17, 2013, the Company issued $350.0 million aggregate principal amount of 8.00% senior secured second lien notes due 2019 (the "2019 Secured Notes") at par. The 2019 Secured Notes are secured by the same assets that secure indebtedness under the senior secured credit facility, but on a second priority basis, subject to certain exceptions and permitted liens. Interest is payable on the 2019 Secured Notes on January 15 and July 15 of each year. The Company may redeem some or all of the notes at prices that are reflected as a percentage of the principal amount, as follows: 104.0% commencing January 15, 2016, 102.0% commencing January 15, 2017, and 100% on or after January 15, 2018.

2020 Notes

The Company has outstanding $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 ("2020 Notes") at par. Interest is payable on the 2020 Notes on April 1 and October 1 of each year. The Company may redeem some or all of the 2020 Notes during the respective 12 month periods at prices that are reflected as a percentage of the principal amount, as follows: 103.625% commencing October 1, 2015; 102.417% commencing October 1, 2016; 101.208% commencing October 1, 2017; and 100% on or after October 1, 2018.

2019 7% Notes and 2021 Notes

The Company has outstanding $1.0 billion of 7.00% unsecured senior notes due 2019 ("2019 7% Notes") and $1.0 billion of 7.25% unsecured senior notes due 2021 ("2021 Notes"). Interest is payable on the 2019 7% Notes and 2021 Notes on June 15 and December 15 of each year. The Company may redeem some or all of the 2019 7% Notes at prices that are reflected as a percentage of the principal amount, as follows: 103.5% commencing June 15, 2015; 101.75% commencing June 15, 2016; and 100% on or after June 15, 2017. The Company may redeem some or all of the 2021 Notes at prices that are reflected as a percentage of the principal amount, as follows: 103.625% commencing June 15, 2016; 102.417% commencing June 15, 2017; 101.208% commencing June 15, 2018 and 100% on or after June 15, 2019. In each case, accrued and unpaid interest at the redemption date is due upon redemption.

Other Debt Retirements

On December 17, 2013, the Company retired the outstanding $600 million in aggregate principal amount of 8.75% senior unsecured notes due 2016 ("2016 Notes") for $628.7 million with the proceeds from the incremental term loan and the 2019 Secured Notes.

On May 16, 2012, Arch Western Finance accepted for purchase an aggregate of approximately $304.0 million principal amount of its 6.75% Senior Notes due 2013 for $308.0 million. On May 30, 2012, the remaining notes with an outstanding principal amount of $146.0 million were redeemed at par value.

Debt Maturities

The expected maturities of debt are as follows:

Year	
2015	$ 36,915
2016	29,875
2017	30,091
2018	1,858,145
2019	1,730,670
Thereafter	1,500,960
	$5,186,656

Debt Covenants

Financial covenant requirements may restrict the amount of unused capacity available to the Company for borrowings and letters of credit under credit facilities. The credit facility amendment on December 17, 2013 amended financial maintenance covenants to include only a minimum liquidity test until June, 2015, at which time a maximum secured leverage ratio test takes effect. The amendment also limits dividends to one cent per share per fiscal year.

Terms of the Company's credit facilities and leases also contain covenants that limit the ability of the Company to, among other things, acquire, dispose, merge or consolidate assets; incur additional debt; pay dividends and make distributions or repurchase stock; make investments; create liens; issue and sell capital stock of subsidiaries; enter into restrictions affecting the ability of restricted subsidiaries to make distributions, loans or advances to the Company; engage in transactions with affiliates and enter into sale and leaseback transactions. Failure by the Company to comply with such covenants could result in an event of default, which, if not cured or waived, could have a material adverse effect on the Company.

Financing Costs

The Company paid financing costs of $4.5 million, $20.5 million and $50.6 million in conjunction with its financing activities during the years ended December 31, 2014, 2013 and 2012, respectively.

During the years ended December 31, 2013 and 2012, the Company wrote off deferred financing costs of $5.4 million and $1.1 million, respectively, and $6.9 million of unamortized discount and $0.8 million of unamortized issue premium, respectively, related to the redemption of senior notes. In addition, the Company wrote off $1.9 million and $23.4 million of deferred financing costs relating to the reduction in capacity of the senior secured revolving credit facility during the years ended December 31, 2013 and 2012 respectively. The write-off of deferred financing fees, along with other transaction fees associated with these transactions, is reflected in the line "Net loss resulting from early retirement and refinancing of debt" in the consolidated statement of operations.

14. Taxes

The Company is subject to U.S. federal income tax as well as income tax in multiple state jurisdictions. The tax years 2002 through 2014 remain open to examination for U.S. federal income tax matters and 1998 through 2014 remain open to examination for various state income tax matters.

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

	Year Ended December 31		
	2014	2013	2012
		(In thousands)	
Current:			
Federal	$ —	$ —	$ (20,022)
State	25	(647)	575
Total current	25	(647)	(19,447)
Deferred:			
Federal	18,535	(318,956)	(341,486)
State	7,074	(15,895)	7,026
Total deferred	25,609	(334,851)	(334,460)
	$25,634	$(335,498)	$(353,907)

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

	Year Ended December 31		
	2014	2013	2012
		(In thousands)	
Income tax provision (benefit) at statutory rate	$(186,452)	$(378,463)	$(382,581)
Percentage depletion allowance	(12,692)	(15,796)	(33,654)
Goodwill	—	70,301	56,916
State taxes, net of effect of federal taxes	(3,903)	(25,265)	(24,231)
Change in valuation allowance	226,929	8,659	31,832
Other, net	1,752	5,066	(2,189)
	$ 25,634	$(335,498)	$(353,907)

In 2014, 2013 and 2012, compensatory stock options and other equity based compensation awards were exercised resulting in a tax expense (benefit) of $1.6 million, $1.5 million and $0.3 million, respectively. The tax benefit will be recorded in paid-in capital at such point in time when a cash tax benefit is recognized.

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:

	December 31,	
	2014	2013
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 871,848	$ 660,916
Alternative minimum tax credit carryforwards	127,169	126,755
Reclamation and mine closure	114,430	113,843
Goodwill	50,072	52,636
Workers' compensation	38,924	31,641
Share based compensation	30,283	28,494
Acquired sales contracts	26,833	33,392
Retiree benefit plans	22,913	20,527
Contract obligations	15,693	19,327
Other, primarily accrued liabilities	64,503	68,969
Gross deferred tax assets	1,362,668	1,156,500
Valuation allowance	(270,251)	(43,322)
Total deferred tax assets	1,092,417	1,113,178
Deferred tax liabilities:		
Plant and equipment	1,354,396	1,364,382
Deferred development	95,129	91,126
Investment in tax partnerships	7,377	8,170
Other	5,533	13,902
Total deferred tax liabilities	1,462,435	1,477,580
Net deferred liability	$ 370,018	$ 364,402

The Company has federal net operating loss carryforwards for regular income tax purposes of $2.4 billion at December 31, 2014 that will expire between 2022 and 2034. The Company has an alternative minimum tax credit carryforward of $127.2 million at December 31, 2014, which has no expiration date and can be used to offset future regular tax in excess of the alternative minimum tax.

The Company recorded increases in its valuation allowance against its deferred tax assets of $226.9 million, $8.7 million and $31.8 million in 2014, 2013 and 2012, respectively. In 2014, the Company determined that it would not realize the all of the benefit from federal and state net operating losses, based on projections of reversing timing differences in the future. Adjustments in 2013 and 2012 relate to certain state and foreign net operating loss benefits.

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

	(In thousands)
Balance at January 1, 2012	$ 8,798
Additions based on tax positions related to the current year	409
Additions for tax positions of prior years	21,943
Balance at December 31, 2012	31,150
Additions based on tax positions related to the current year	1,199
Additions for tax positions of prior years	688
Reductions as a result of lapses in the statute of limitations	(1,248)
Balance at December 31, 2013	31,789
Additions for tax positions of the current year	2,920
Balance at December 31, 2014	$34,709

If recognized, the entire amount of the gross unrecognized tax benefits at December 31, 2014 would affect the effective tax rate.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company had accrued interest and penalties of $1.5 million and $1.3 million at December 31, 2014 and 2013, 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:

	Year Ended December 31,	
	2014	2013
	(In thousands)	
Balance at January 1 (including current portion)	$427,653	$448,625
Accretion expense	32,909	35,727
Obligations of divested operations	(30,684)	(8,440)
Adjustments to the liability from changes in estimates	627	(26,578)
Liabilities settled	(12,387)	(21,681)
Balance at December 31	$418,118	$427,653
Current portion included in accrued expenses	(19,222)	(24,940)
Noncurrent liability	$398,896	$402,713

As of December 31, 2014, the Company had $177.7 million in surety bonds outstanding, $458.5 million in self-bonding, and $3.5 million in letters of credit to secure reclamation bonding obligations.

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, 2014 and 2013.

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:

	Fair Value at December 31, 2014			
	Total	Level 1	Level 2	Level 3
	(In thousands)			
Assets:				
Investments in marketable securities	$254,099	$ 5,145	$248,954	$ —
Derivatives	13,557	9,026	1,491	3,040
Total assets	$267,656	$14,171	$250,445	$3,040
Liabilities:				
Derivatives	$ 766	$ —	$ 766	$ —

	Fair Value at December 31, 2013			
	Total	Level 1	Level 2	Level 3
	(In thousands)			
Assets:				
Investments in marketable securities	$264,443	$77,967	$186,476	$ —
Derivatives	19,954	14,847	—	5,107
Total assets	$284,397	$92,814	$186,476	$5,107
Liabilities:				
Derivatives	$ 12	$ —	$ (149)	$ 161

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.

	Year Ended December 31,	
	2014	2013
	(In thousands)	
Balance, beginning of period	$ 4,946	$ 8,174
Realized and unrealized losses recognized in earnings, net	(6,572)	(10,253)
Purchases	5,288	8,654
Issuances	(622)	(25)
Settlements	—	(1,604)
Ending balance	$ 3,040	$ 4,946

Net unrealized losses of $2.1 million were recognized during the year ended December 31, 2014 related to level 3 financial instruments held on December 31, 2014.

Cash and Cash Equivalents

At December 31, 2014 and 2013, the carrying amounts of cash and cash equivalents approximate their fair value.

Fair Value of Long-Term Debt

At December 31, 2014 and 2013, the fair value of the Company's debt, including amounts classified as current, was $2.7 billion and $4.6 billion, 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

On March 1, 2012, the Company filed a registration statement on Form S-3 with the SEC. The registration statement allows the Company to offer, from time to time, an unlimited amount of debt securities, preferred stock, depositary shares, purchase contracts, purchase units, common stock and related rights and warrants.

Stock Repurchase Plan

The Company's share repurchase program allows for the purchase of up to 14,000,000 shares of the Company's common stock. At December 31, 2014, 10,925,800 shares of common stock were available for repurchase under the plan. There is no expiration date on the program. Any future repurchases under the plan will be made at management's discretion and will depend on market conditions and other factors.

18. Stock-Based Compensation and Other Incentive Plans

Under the Company's Stock Incentive Plan (the ''Incentive Plan''), 30.9 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, merit awards, 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 10.3 million at December 31, 2014.

Stock Options

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 at least one year from the date of grant. Information regarding stock option activity under the Incentive Plan follows for the year ended December 31, 2014:

	Common Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value	Average Remaining Life Years
		(In thousands)		
Options outstanding at January 1	6,939	$19.86		
Canceled	(88)	$17.61		
Expired	(29)	$29.84		
Options outstanding at December 31	6,822	$19.84	$—	5.679
Options exercisable at December 31	5,123	$24.01	—	5.0
Unvested options at December 31	1,699			

The remaining unvested options have a weighted average fair value of $3.10 per share.

The total grant-date fair value of options vested during the years ended December 31, 2014, 2013 and 2012 was $8.7 million, $8.9 million and $8.0 million, respectively. The options provide for the continuation of vesting for retirement-eligible recipients that meet certain criteria. The expense for these options is recognized through the date that the employee first becomes eligible to retire and is no longer required to provide service to earn part or all of the award. Compensation expense related to stock options for the years ended December 31, 2014, 2013 and 2012 was $3.2 million, $6.7 million and $8.0 million, respectively. Unrecognized compensation cost related to the unvested stock options of $1.6 million at December 31, 2014 will be recognized in 2015.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.

Weighted average assumptions used in the Black-Scholes option pricing model for granted options follow:

	Year Ended December 31,	
	2013	2012
Weighted average grant-date fair value per share of options granted	$2.37	$5.27
Assumptions (weighted average):		
Risk-free interest rate	0.65%	0.76%
Expected dividend yield	2.30%	2.92%
Expected volatility	66.7%	60.7%
Expected life (in years)	4.5	4.5

Expected volatilities are based on historical stock price movement and implied volatility from traded options on the Company's stock. The expected life of options is determined based on historical exercise activity.

Restricted Stock and 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 three years. Compensation expense is based on the fair value on the grant date and is recorded ratably over the vesting period. The employee receives cash compensation equal to the amount of dividends that would have been paid on the underlying shares.

Information regarding restricted stock and restricted stock unit activity and weighted average grant-date fair value follows for the year ended December 31, 2014:

	Restricted Stock		Restricted Stock Units	
	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value
Outstanding at January 1	143	$27.52	1,373	$7.95
Granted	—	—	1,521	4.51
Vested	(120)	30.08	—	—
Canceled	(1)	32.49	(70)	6.34
Outstanding at December 31	22	13.44	2,824	6.14

The Company's recognized expense related to restricted stock and restricted stock units was $5.6 million, $5.0 million, and $3.5 million for the years ended December 31, 2014, 2013 and 2012, respectively

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 $10.1 million, $9.1 million and $8.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. The expense is included primarily in "Selling, general and administrative expenses" in the accompanying consolidated statements of operations. Amounts accrued and unpaid for all grants under the plan totaled $21.1 million and $17.2 million as of December 31, 2014 and 2013, respectively.

Deferred Compensation Plan

The Company maintains a deferred compensation plan that allows eligible employees to defer receipt of compensation until the dates elected by the participant. Participants in the plan may defer up to 85% of their base salaries and up to 100% of their annual incentive awards. The plan also allows participants to defer receipt of up to 100% of the shares under any restricted stock unit or performance-contingent stock awards. The amounts deferred are invested in accounts that mirror the gains and losses of a number of different investment funds, including a hypothetical investment in shares of the Company's common stock. Participants are always vested in their deferrals to the plan and any related earnings. The Company has established a grantor trust to fund the obligations under the plan. The trust has purchased corporate-owned life insurance to offset these obligations. The net cash surrender values of the policies of $37.6 million and $39.4 million at December 31, 2014 and 2013, respectively, are included in "Other noncurrent assets" in the accompanying consolidated balance sheets. The participants have an unsecured contractual commitment by the Company to pay the amounts due under the plan. Any assets placed in trust by the Company to fund future obligations of the plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Under the plan, the Company credits each participant's account with the number of units equal to the number of shares or units that the participant could purchase or receive with the amount of compensation deferred, based upon the fair market value of the underlying investment on that date. The amount the employee will receive from the plan will be based on the number of units credited to each participant's account, valued on the basis of the fair market value of an equivalent number of shares or units of the underlying investment on that date. The liability under the plan was $35.1 million and $37.0 million at December 31, 2014 and 2013.

The Company's net income related to the deferred compensation plan for the years ended December 31, 2014, 2013 and 2012 was $1.6 million, $2.6 million and $3.3 million, respectively, most of which is included in "Selling, general and administrative expenses in the accompanying consolidated statements of operations.

19. Workers' Compensation Expense

The following table details the components of workers' compensation expense:

	Year Ended December 31,		
	2014	2013	2012
		(In thousands)	
Total occupational disease	4,432	6,137	6,962
Traumatic injury claims and assessments	19,924	21,089	26,565
Total workers' compensation expense	$24,356	$27,226	$33,527

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

	December 31,	
	2014	2013
	(In thousands)	
Occupational disease costs	$ 72,749	$55,228
Traumatic and other workers' compensation claims	38,256	35,268
Total obligations	111,005	90,496
Less amount included in accrued expenses	16,714	12,434
Noncurrent obligations	$ 94,291	$78,062

As of December 31, 2014, the Company had $121.4 million in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

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 benefits at the amount accrued at that date. 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.

A curtailment was triggered in the third quarter of 2013 by reductions in employees' expected years of future service resulting primarily from the sale of Canyon Fuel.

Obligations and Funded Status.

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

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
	(In thousands)			
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligations at January 1	$355,468	$390,894	$ 42,531	$ 49,326
Service cost	21,478	27,065	1,649	2,027
Interest cost	17,070	16,207	1,841	1,739
Plan amendments	(23)	—	—	—
Curtailments	(25,787)	(3,027)	—	(2,519)
Benefits paid	(53,974)	(41,562)	(3,431)	(3,276)
Other-primarily actuarial loss (gain)	39,504	(34,109)	(6,492)	(4,766)
Benefit obligations at December 31	$353,736	$355,468	$ 36,098	$ 42,531
CHANGE IN PLAN ASSETS				
Value of plan assets at January 1	$347,952	$322,874	$ —	$ —
Actual return on plan assets	36,130	52,247	—	—
Employer contributions	6,601	14,393	3,431	3,276
Benefits paid	(53,974)	(41,562)	(3,431)	(3,276)
Value of plan assets at December 31	$336,709	$347,952	$ —	$ —
Accrued benefit cost	$ (17,027)	$ (7,516)	$(36,098)	$(42,531)
ITEMS NOT YET RECOGNIZED AS A COMPONENT OF NET PERIODIC BENEFIT COST				
Prior service credit (cost)	$ —	$ 1,732	$ 21,972	$ 31,925
Accumulated gain (loss)	(11,332)	10,096	9,125	3,394
	$ (11,332)	$ 11,828	$ 31,097	$ 35,319
BALANCE SHEET AMOUNTS				
Current liability	$ (767)	$ (405)	$ (3,430)	$ (3,276)
Noncurrent liability	$ (16,260)	$ (7,111)	$(32,668)	$(39,255)
	$ (17,027)	$ (7,516)	$(36,098)	$(42,531)

Pension Benefits

The accumulated benefit obligation for all pension plans was $353.7 million and $341.1 million at December 31, 2014 and 2013, respectively. The accumulated benefit obligation differs from the benefit obligation in that it includes no assumptions about future compensation levels.

Net actuarial loss of $8.2 million will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2015.

Other Postretirement Benefits

Prior service credit and net actuarial gain of $8.3 million and $1.8 million, respectively, will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2015.

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

	Pension Benefits			Other Postretirement Benefits		
	Year Ended December 31,			Year Ended December 31,		
	2014	2013	2012	2014	2013	2012
	(In thousands)					
Service cost	$ 21,478	$ 27,065	$ 27,466	$ 1,649	$ 2,027	$ 2,142
Interest cost	17,070	16,207	15,668	1,841	1,739	2,020
Curtailments	(25,368)	47	324	—	(5,444)	(4,049)
Settlements	646	—	—	—	—	—
Expected return on plan assets	(23,756)	(23,761)	(22,030)	—	—	—
Amortization of prior service credits	(257)	(204)	259	(10,003)	(10,621)	(11,458)
Amortization of other actuarial losses	3,128	14,616	14,666	(761)	(252)	(522)
Net benefit cost (credit)	$ (7,059)	$ 33,970	$ 36,353	$ (7,274)	$(12,551)	$(11,867)

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period.

Assumptions. The following table provides the weighted average assumptions used to determine the actuarial present value of projected benefit obligations at December 31 of the respective years.

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	4.15%	5.08%	3.91%	4.58%
Rate of compensation increase	N/A	3.39%	N/A	N/A

The following table provides the weighted average assumptions used to determine net periodic benefit cost for the respective years ended December 31.

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Discount rate	5.08/4.23/4.14%	4.13/5.05%	4.91%	4.58%	3.64/4.58%	4.52%
Rate of compensation increase	3.39%	3.39%	3.39%	N/A	N/A	N/A
Expected return on plan assets	7.75%	7.75%	7.75%	N/A	N/A	N/A

The discount rates used in 2014 and 2013 were reevaluated during the year for settlements and the curtailments as described previously. 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 2015 is 7.1% and is expected to reach an ultimate trend rate of 4.5% by 2028. A one-percentage-point increase in the health care cost trend rate would not have increased the postretirement benefit obligation at December 31, 2014 or the net periodic postretirement benefit cost for the year ended December 31, 2014 by a material amount.

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 65% equity and 35% 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, 2014 and 2013, 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	
	2014	2013	2014	2013	2014	2013	2014	2013
	(In thousands)							
Equity Securities:(A)								
U.S. small-cap	$ 16,512	$ 14,901	$16,512	$ 14,901	$ —	$ —	$ —	$ —
U.S. mid-cap	46,481	62,271	17,301	28,654	29,180	33,617	—	—
U.S. large-cap	89,008	110,947	43,181	53,708	45,827	57,239	—	—
Non-U.S.	25,905	29,165	—	—	25,905	29,165	—	—
Fixed income securities:								
U.S. government securities(B)	13,708	18,545	12,988	17,714	720	831	—	—
Non-U.S. government securities(C)	1,599	2,143	—	—	1,599	2,143	—	—
U.S. government asset and mortgage backed securities(D)	830	600	—	—	830	600	—	—
Corporate fixed income(E)	22,702	9,902	—	—	22,702	9,902	—	—
State and local government securities(F)	8,005	8,301	—	—	8,005	8,301	—	—
Other fixed income(G)	83,735	58,093	—	—	83,735	58,093	—	—
Short-term investments(H)	6,818	14,663	—	—	6,818	14,663	—	—
Other investments(I)	21,406	18,421	—	—	3,336	1,404	18,070	17,017
Total	$336,709	$347,952	$89,982	$114,977	$228,657	$215,958	$18,070	$17,017

(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 includes 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.

During 2013, the plan invested $16.0 million in Level 3 investments. Subsequent changes in fair value are the result of unrealized gains on the investment.

Cash Flows. The Company expects to make contributions of $0.5 million to the pension plans in 2015, 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)	
2015	$ 17,737	$ 3,665
2016	20,544	3,657
2017	22,503	3,551
2018	24,086	3,486
2019	22,943	3,421
Next 5 years	130,088	14,680
	$237,901	$32,460

Other Plans

The Company sponsors savings plans which were established to assist eligible employees provide for their future retirement needs. The Company's expense, representing its contributions to the plans, was $22.9 million, $25.1 million and $27.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

21. Earnings (Loss) Per Common Share

The effect of options, restricted stock and restricted stock units representing 7.7 million , 7.5 million, and 4.9 million shares of common stock were excluded from the calculation of diluted weighted average shares outstanding for the years ended December 31, 2014, 2013 and 2012, respectively because the exercise price or grant price of the securities exceeded the average market price of the Company's common stock for these periods. The effect of options, restricted stock and restricted stock units representing 2.0 million shares were excluded from the calculation of weighted average shares due to the Company's incurring a net loss for the years ended December 31, 2014.

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, 2014 are as follows:

	Operating Leases	Royalties
	(In thousands)	
2015	$25,685	$ 14,587
2016	19,242	18,632
2017	17,065	17,932
2018	6,334	17,584
2019	3,370	13,875
Thereafter	11,880	83,282
	$83,576	$165,892

Obligations for the future minimum payments under capital leases for equipment totaling $46.0 million and $20.8 million at December 31, 2014 and 2013, 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 $42.9 million in 2014, $42.2 million in 2013 and $41.2 million in 2012.

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 $242.5 million in 2014, $261.1 million in 2013 and $302.0 million in 2012.

As of December 31, 2014, certain of the Company's lease obligations were secured by outstanding surety bonds totaling $49.4 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, 2014 and 2013, accounts receivable from electric utilities of $134.7 million and $125.7 million, respectively, represented 64% of total trade receivables at each date. As of December 31, 2014 and 2013, accounts receivable from sales of metallurgical-quality coal of $76.0 million and $70.5 million, respectively, represented 36% 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:

	Year Ended December 31,		
	2014	2013	2012
		(In thousands)	
Europe	$277,565	$371,363	$ 674,754
Asia	156,057	160,404	203,193
North America	78,445	80,322	72,542
Central and South America	20,496	55,493	57,184
Brokered Sales	79,354	154,442	145,438
Total	$611,917	$822,024	$1,153,111

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. The Company sold approximately 134.4 million tons of coal in 2014. Approximately 60% of this tonnage (representing approximately 48% 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 6 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. Settlement with Patriot Coal

On December 31, 2005, Arch entered into a purchase and sale agreement to sell mining complexes to Magnum Coal Company (''Magnum''). On July 23, 2008, Patriot Coal Corporation acquired Magnum from Arc Light Capital Partners. On July 9, 2012, Patriot Coal Corporation and certain of its wholly owned subsidiaries, including Magnum, (collectively, ''Patriot'') filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Southern District of New York.

On October 4, 2013, we entered into a term sheet that was approved by the U.S. Bankruptcy Court on November 7, 2013, that resolves all pending and potential legal claims with Patriot stemming from the Company's sale of mining complexes to Magnum and the subsequent purchase of those companies by Patriot in 2008.

The Company paid $5.0 million in cash to Patriot upon its exit from bankruptcy, which is reflected in ''Other operating income, net'' in the consolidated statement of operations for the year ended December 31, 2013.

25. 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.

Allegheny Energy Supply (''Allegheny''), the sole customer of coal produced at the Company's subsidiary Wolf Run Mining Company's (''Wolf Run'') Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. (''Hunter Ridge''), and ICG in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claimed that Wolf Run breached a coal supply contract when it declared force majeure under the contract upon idling the Sycamore No. 2 mine in the third quarter of 2006, and that Wolf Run continued to breach the contract by failing to ship in volumes referenced in the contract. The Sycamore

No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped.

After extensive searching for gas wells and rehabilitation of the mine, it was re-opened in 2007, but with notice to Allegheny that it would necessarily operate at reduced volumes in order to safely and effectively avoid the many gas wells within the reserve. The amended complaint also alleged that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005. Allegheny voluntarily dropped the breach of representation claims later. Allegheny claimed that it would incur costs in excess of $100 million to purchase replacement coal over the life of the contract. ICG, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims.

On November 3, 2008, ICG, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and conspiracy. On September 23, 2009, Allegheny filed a second amended complaint alleging several alternative theories of liability in its effort to extend contractual liability to ICG, which was not a party to the original contract and did not exist at the time Wolf Run and Allegheny entered into the contract. No new substantive claims were asserted. ICG answered the second amended complaint on October 13, 2009, denying all of the new claims. The Company's counterclaim was dismissed on motion for summary judgment entered on May 11, 2010. Allegheny's claims against ICG were also dismissed by summary judgment, but the claims against Wolf Run and Hunter Ridge were not. The court conducted a non-jury trial of this matter beginning on January 10, 2011 and concluding on February 1, 2011.

At the trial, Allegheny presented its evidence for breach of contract and claimed that it is entitled to past and future damages in the aggregate of between $228 million and $377 million. Wolf Run and Hunter Ridge presented their defense of the claims, including evidence with respect to the existence of force majeure conditions and excuse under the contract and applicable law. Wolf Run and Hunter Ridge presented evidence that Allegheny's damages calculations were significantly inflated because it did not seek to determine damages as of the time of the breach and in some instances artificially assumed future nondelivery or did not take into account the apparent requirement to supply coal in the future. On May 2, 2011, the trial court entered a Memorandum and Verdict determining that Wolf Run had breached the coal supply contract and that the performance shortfall was not excused by force majeure. The trial court awarded total damages and interest in the amount of $104.1 million, which consisted of $13.8 million for past damages, and $90.3 million for future damages. ICG and Allegheny filed post-verdict motions in the trial court and on August 23, 2011, the court denied the parties' motions. The court entered a final judgment on August 25, 2011, in the amount of $104.1 million, which included pre-judgment interest.

The parties appealed the lower court's decision to the Superior Court of Pennsylvania. On August 13, 2012, the Superior Court of Pennsylvania affirmed the award of past damages, but ruled that the lower court should have calculated future damages as of the date of breach, and remanded the matter back to the lower court with instructions to recalculate that portion of the award. On November 19, 2012, Allegheny filed a Petition for Allowance of Appeal with the Supreme Court of Pennsylvania and Wolf Run and Hunter Ridge filed an Answer. On July 2, 2013, the Supreme Court of Pennsylvania denied the Petition of Allowance. As this action finalized the past damage award, Wolf Run paid $15.6 million for the past damage amount, including interest, to Allegheny in July 2013.

The court held a hearing on this matter on November 5, 2014 and on February 16, 2015 awarded Allegheny $7.5 million plus interest for the future damages.

In addition, the Company is a party to numerous claims and lawsuits with respect to various matters. As of December 31, 2014 and 2013, the Company had accrued $22.3 million and $30.4 million, respectively, for all legal matters, including $10.1 million and $11.7 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 $265.6 million in 2015, $118.1 million in 2016, $114.7 million in 2017, $82.2 million in 2018, $73.5 million in 2019 and $279.4 million thereafter. During the years ended December 31, 2014, 2013 and 2012, the Company fulfilled its commitments under agreements containing unconditional obligations. The Company recognized expense relating to transportation capacity agreements of $36.5 million, $12.0 million, and $2.3 million during the years ended December 31, 2014, 2013 and 2012, respectively.

26. Segment Information

The Company's reportable business segments are based on the major coal producing basins in which the Company operates and may include a number of mine complexes. The Company manages its coal sales by coal basin, not by individual mining complex. Geology, coal transportation routes to customers, regulatory environments and coal quality or type are characteristic to a basin, and, accordingly, market and contract pricing have developed by coal basin. Mining operations are evaluated based on their per-ton operating costs (defined as including all mining costs but excluding pass-through transportation expenses), as well as on other non-financial measures, such as safety and environmental performance. The Company's reportable segments are the Powder River Basin (PRB) segment, with operations in Wyoming; and the Appalachia (APP) segment, with operations in West Virginia, Kentucky, Maryland and Virginia. "All Other" includes the Company's coal mining operations in Colorado and Illinois and our ADDCAR subsidiary.

In 2014, the Company changed its measure of segment profit and loss to assess operating segment's performance and to allocate resources from "income from operations" to "adjusted earnings before interest, taxes, depreciation, depletion and amortization (Adjusted EBITDA)." The Company's management believes that Adjusted EBITDA presents a useful measure of our ability to service existing debt and incur additional debt based on ongoing operations. Adjusted EBITDA 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 acquired sales contracts and other unassigned assets.

	PRB	APP	All Other	Corporate, Other and Eliminations	Consolidated
Year Ended December 31, 2014					
Revenues	$1,490,377	$1,108,358	$338,384	$ —	$ 2,937,119
Adjusted EBITDA	198,074	110,693	56,612	(85,236)	280,143
Depreciation, depletion and amortization	168,522	205,732	40,125	4,369	418,748
Amortization of acquired sales contracts, net	(3,961)	(9,433)	207	—	(13,187)
Total assets	1,772,230	3,379,834	339,809	2,937,850	8,429,723
Capital expenditures	44,305	23,638	12,993	66,350	147,286
Year Ended December 31, 2013					
Revenues	$1,482,812	$1,145,801	$385,744	$ —	$ 3,014,357
Adjusted EBITDA	206,910	88,883	94,948	(138,595)	252,146
Depreciation, depletion and amortization	171,324	202,952	45,741	6,425	426,442
Amortization of acquired sales contracts, net	(3,656)	(10,364)	4,563	—	(9,457)
Total assets	1,841,835	3,971,764	402,922	2,773,672	8,990,193
Capital expenditures	9,784	167,759	23,122	96,319	296,984
Year Ended December 31, 2012					
Revenues	$1,524,536	$1,793,576	$450,014	$ —	$ 3,768,126
Adjusted EBITDA	262,155	405,981	112,982	(201,246)	579,872
Depreciation, depletion and amortization	166,539	271,221	49,911	4,540	492,211
Amortization of acquired sales contracts, net	(1,987)	(23,926)	724	—	(25,189)
Total assets	1,972,522	3,875,105	834,287	3,324,863	10,006,777
Capital expenditures	23,410	275,476	68,220	28,119	395,225

A reconciliation of segment losses to consolidated loss from continuing operations before income taxes follows:

	Year Ended December 31, 2014	2013	2012
Adjusted EBITDA	$ 280,143	$ 252,146	$ 579,872
Depreciation, depletion and amortization	(418,748)	(426,442)	(492,211)
Amortization of acquired sales contracts, net	13,187	9,457	25,189
Asset impairment costs	(24,113)	(220,879)	(539,182)
Goodwill impairment	—	(265,423)	(330,680)
Settlement of UMWA legal claims	—	(12,000)	—
Interest expense, net	(383,188)	(374,664)	(312,142)
Nonoperating expense	—	(42,921)	(23,668)
Loss from continuing operations before income taxes	$(532,719)	$(1,080,726)	$(1,092,822)

27. Quarterly Selected Financial Data

Year Ended December 31, 2014	March 31 (a)	June 30 (a)(c)	September 30 (a)(c)	December 31 (a)(c)
	(In thousands, except per share data)			
Revenues	$ 735,971	$713,776	$742,180	$ 745,192
Gross profit (loss)	$ (49,842)	$ (6,350)	$ (5,851)	$ 32,264
Asset impairment and mine closure costs	$ —	$ 1,512	$ 5,060	$ 17,541
Loss from operations	$ (73,123)	$ (35,805)	$ (35,300)	$ (5,303)
Net loss	$(124,140)	$ (96,860)	$ (97,218)	$(240,135)
Diluted loss per common share	$ (0.59)	$ (0.46)	$ (0.46)	$ (1.13)

Year Ended December 31, 2013	March 31 (a)	June 30 (a)	September 30 (a)	December 31 (a)
	(In thousands, except per share data)			
Revenues	$737,370	$766,332	$ 791,269	$ 719,386
Gross profit (loss)	$ (18,560)	$ 2,505	$ 90	$ (44,801)
Asset impairment and mine closure costs	$ —	$ 20,482	$ 200,397	$ —
Goodwill impairment	$ —	$ —	$ —	$ 265,423
Loss from operations	$ (51,431)	$ (36,279)	$(234,753)	$(340,678)
Loss from continuing operations	$ (84,316)	$ (80,351)	$(207,767)	$(372,794)
Income from discontinued operations, net of tax[b]	$ 14,267	$ 8,145	$ 79,404	$ 1,580
Net loss	$ (70,049)	$ (72,206)	$(128,363)	$(371,214)
Diluted loss per common share from:				
Income (loss) from continuing operations	$ (0.40)	$ (0.38)	$ (0.98)	$ (1.76)
Net loss	$ (0.33)	$ (0.34)	$ (0.61)	$ (1.75)

(a) Challenging coal markets resulted in impairment charges relating to mining and other operations, investments in equity method subsidiaries, prepaid mining royalties and goodwill in 2014 and 2013. See further discussion in Note 5, "Impairment Charges and Mine Closure Costs", Note 6, "Goodwill", and Note 9, "Equity Method Investments and Membership Interests in Joint Ventures."

(b) The Company entered into a definitive agreement on June 27, 2013 to sell Canyon Fuel and the sale was completed on August 16, 2013. Beginning in the second quarter of 2013, all quarterly filings with the Securities and Exchange Commission reflected Canyon Fuel as a discontinued operation in the consolidated statements of operations. See further information in Note 3, "Divestitures".

(c) The Company determined that it would not realize the benefit from federal and state net operating losses it generated in 2014, based on projections of future taxable income, and as a result, recorded a valuation allowance against net operating losses of $23.8 million, $18.3 million, $15.8 million and $169.0 million in the second, third and fourth quarters of 2014, respectively.

28. Supplemental Consolidating Financial Information

Pursuant to the indentures governing Arch Coal, Inc.'s senior notes, certain wholly-owned subsidiaries of the Company have fully and unconditionally guaranteed the senior notes on a joint and several basis. The following tables present consolidating financial information for (i) the Company, (ii) the issuer of the senior notes, (iii) the guarantors under the senior notes, and (iv) the entities which are not guarantors under the senior notes (Arch Receivable Company, LLC and the Company's subsidiaries outside the United States):

Condensed Consolidating Statements of Operations and Comprehensive Income
Year Ended December 31, 2014

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
Revenues	$ —	$2,937,119	$ —	$ —	$2,937,119
Costs, expenses and other					
Cost of sales (exclusive of items shown separately below)	3,016	2,566,572	—	(3,395)	2,566,193
Depreciation, depletion and amortization	5,154	413,559	35	—	418,748
Amortization of acquired sales contracts, net	—	(13,187)	—	—	(13,187)
Change in fair value of coal derivatives and coal trading activities, net	—	(3,686)	—	—	(3,686)
Asset impairment and mine closure costs	3,642	20,471	—	—	24,113
Selling, general and administrative expenses	79,902	29,739	6,626	(2,044)	114,223
Other operating income, net	(4,480)	(15,726)	(4,987)	5,439	(19,754)
	87,234	2,997,742	1,674	—	3,086,650
Loss from investment in subsidiaries	(13,085)	—	—	13,085	—
Loss from operations	(100,319)	(60,623)	(1,674)	13,085	(149,531)
Interest expense, net					
Interest expense	(463,823)	(26,137)	(4,259)	103,273	(390,946)
Interest and investment income	31,389	74,511	5,131	(103,273)	7,758
	(432,434)	48,374	872	—	(383,188)
Loss from continuing operations before income taxes	(532,753)	(12,249)	(802)	13,085	(532,719)
Provision for (benefit from) income taxes	25,600	—	34	—	25,634
Net loss	(558,353)	(12,249)	(836)	13,085	(558,353)
Total comprehensive loss	$(592,804)	$ (34,439)	$ (836)	$ 35,275	$ (592,804)

Condensed Consolidating Statements of Operations and Comprehensive Income
Year Ended December 31, 2013

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Revenues	$ —	$3,014,357	$ —	$ —	$ 3,014,357
Costs, expenses and other					
Cost of sales (exclusive of items shown separately below)	9,117	2,657,583	—	(3,564)	2,663,136
Depreciation, depletion and amortization	5,949	420,458	35	—	426,442
Amortization of acquired sales contracts, net	—	(9,457)	—	—	(9,457)
Change in fair value of coal derivatives and coal trading activities, net	—	7,845	—	—	7,845
Asset impairment and mine closure costs	78,150	142,729	—	—	220,879
Goodwill impairment	—	265,423	—	—	265,423
Selling, general and administrative expenses	88,820	39,825	7,038	(2,235)	133,448
Other operating income, net	4,209	(34,856)	(5,370)	5,799	(30,218)
	186,245	3,489,550	1,703	—	3,677,498
Loss from investment in subsidiaries	(328,889)	—	—	328,889	—
Loss from operations	(515,134)	(475,193)	(1,703)	328,889	(663,141)
Interest expense, net					
Interest expense	(449,614)	(24,747)	(4,214)	97,308	(381,267)
Interest and investment income	30,285	68,248	5,378	(97,308)	6,603
	(419,329)	43,501	1,164	—	(374,664)
Net loss resulting from early retirement and refinancing of debt	(42,921)	—	—	—	(42,921)
Loss from continuing operations before income taxes	(977,384)	(431,692)	(539)	328,889	(1,080,726)
Provision for (benefit from) income taxes	(335,552)	—	54	—	(335,498)
Loss from continuing operations	(641,832)	(431,692)	(593)	328,889	(745,228)
Income from discontinued operations, including gain on sale—net of tax	—	103,396	—	—	103,396
Net loss	$(641,832)	$ (328,296)	$ (593)	$328,889	$ (641,832)
Total comprehensive loss	$(587,633)	$ (304,278)	$ (593)	$304,871	$ (587,633)

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

Condensed Consolidating Statements of Operations and Comprehensive Income
Year Ended December 31, 2012

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Revenues	$ —	$3,768,126	$ —	$ —	$ 3,768,126
Costs, expenses and other					—
Cost of sales (exclusive of items shown separately below)	10,921	3,144,178	—	—	3,155,099
Depreciation, depletion and amortization	5,392	486,786	33	—	492,211
Amortization of acquired sales contracts, net	—	(25,189)	—	—	(25,189)
Change in fair value of coal derivatives and coal trading activities, net	—	(16,590)	—	—	(16,590)
Asset impairment and mine closure costs	—	539,182	—	—	539,182
Goodwill impairment	—	330,680	—	—	330,680
Contract settlement resulting from Patriot Coal bankruptcy	—	58,335	—	—	58,335
Reduction in accrual related to acquired litigation	—	(79,532)	—	—	(79,532)
Selling, general and administrative expenses	84,199	44,363	8,785	(3,048)	134,299
Other operating income, net	(13,392)	(39,209)	(13,804)	3,048	(63,357)
	87,120	4,443,004	(4,986)	—	4,525,138
Loss from investment in subsidiaries	(589,665)	—	—	589,665	—
Income (loss) from operations	(676,785)	(674,878)	4,986	589,665	(757,012)
Interest expense, net					
Interest expense	(366,584)	(34,849)	(3,221)	87,039	(317,615)
Interest and investment income	27,750	57,268	7,494	(87,039)	5,473
	(338,834)	22,419	4,273	—	(312,142)
Other non-operating expense					
Net loss resulting from early retirement of debt	(21,975)	(1,693)	—	—	(23,668)
Income (loss) from continuing operations before income taxes	(1,037,594)	(654,152)	9,259	589,665	(1,092,822)
Provision for (benefit from) income taxes	(353,907)	—	—	—	(353,907)
Income (loss) from continuing operations	(683,687)	(654,152)	9,259	589,665	(738,915)
Income from discontinued operations, net of tax	—	55,228	—	—	55,228
Net Income (loss)	(683,687)	(598,924)	9,259	589,665	(683,687)
Less: Net income attributable to noncontrolling interest	(268)	—	—	—	(268)
Net Income (loss) attributable to Arch Coal, Inc.	$ (683,955)	$ (598,924)	$ 9,259	$589,665	$ (683,955)
Total comprehensive income (loss)	$ (692,239)	$ (604,903)	$ 9,259	$595,644	$ (692,239)

Condensed Consolidating Balance Sheets
December 31, 2014

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Assets					
Cash and cash equivalents	$ 572,185	$ 150,358	$ 11,688	$ —	$ 734,231
Short term investments	248,954	—	—	—	248,954
Receivables	9,656	15,933	211,043	(4,615)	232,017
Inventories	—	190,253	—	—	190,253
Other	89,211	41,455	6,630	—	137,296
Total current assets	920,006	397,999	229,361	(4,615)	1,542,751
Property, plant and equipment, net	10,470	6,442,623	2	363	6,453,458
Investment in subsidiaries	7,464,221	—	—	(7,464,221)	—
Intercompany receivables	—	2,021,110	—	(2,021,110)	—
Note receivable from Arch Western	675,000	—	—	(675,000)	—
Other	131,884	300,058	1,572	—	433,514
Total assets	$9,201,581	$9,161,790	$230,935	$(10,164,583)	$8,429,723
Liabilities and Stockholders' Equity					
Accounts payable	$ 23,394	$ 156,664	$ 55	$ —	$ 180,113
Accrued expenses and other current liabilities	85,899	220,017	1,095	(4,615)	302,396
Current maturities of debt	27,625	9,260	—	—	36,885
Total current liabilities	136,918	385,941	1,150	(4,615)	519,394
Long-term debt	5,084,839	38,646	—	—	5,123,485
Intercompany payables	1,817,755	—	203,355	(2,021,110)	—
Note payable to Arch Coal	—	675,000	—	(675,000)	—
Asset retirement obligations	981	397,915	—	—	398,896
Accrued pension benefits	5,967	10,293	—	—	16,260
Accrued postretirement benefits other than pension	4,430	28,238	—	—	32,668
Accrued workers' compensation	9,172	85,119	—	—	94,291
Deferred income taxes	422,809	—	—	—	422,809
Other noncurrent liabilities	50,919	102,461	386	—	153,766
Total liabilities	7,533,790	1,723,613	204,891	(2,700,725)	6,761,569
Stockholders' equity	1,667,791	7,438,177	26,044	(7,463,858)	1,668,154
Total liabilities and stockholders' equity	$9,201,581	$9,161,790	$230,935	$(10,164,583)	$8,429,723

Condensed Consolidating Balance Sheets
December 31, 2013

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Assets					
Cash and cash equivalents	$ 799,333	$ 100,418	$ 11,348	$ —	$ 911,099
Short term investments	248,414	—	—	—	248,414
Receivables	14,177	23,018	197,015	(4,637)	229,573
Inventories	—	264,161	—	—	264,161
Other	84,401	43,617	806	—	128,824
Total current assets	1,146,325	431,214	209,169	(4,637)	1,782,071
Property, plant and equipment, net	24,851	6,709,398	37	—	6,734,286
Investment in subsidiaries	7,741,589	—	—	(7,741,589)	—
Intercompany receivables		1,953,719	—	(1,953,719)	—
Note receivable from Arch Western	675,000	—	—	(675,000)	—
Other	162,287	311,463	86	—	473,836
Total other assets	8,578,876	2,265,182	86	(10,370,308)	473,836
Total assets	$9,750,052	$9,405,794	$209,292	$(10,374,945)	$8,990,193
Liabilities and Stockholders' Equity					
Accounts payable	$ 17,781	$ 158,224	$ 137	$ —	$ 176,142
Accrued expenses and other current liabilities	53,779	228,664	781	(4,637)	278,587
Current maturities of debt	28,882	4,611	—	—	33,493
Total current liabilities	100,442	391,499	918	(4,637)	488,222
Long-term debt	5,099,833	18,169	—		5,118,002
Intercompany payables	1,772,624	—	181,095	(1,953,719)	—
Note payable to Arch Coal	—	675,000	—	(675,000)	—
Asset retirement obligations	1,095	401,618	—	—	402,713
Accrued pension benefits	7,797	(686)	—	—	7,111
Accrued postretirement benefits other than pension	12,079	27,176	—	—	39,255
Accrued workers' compensation	21,546	56,516	—	—	78,062
Deferred income taxes	413,546	—	—	—	413,546
Other noncurrent liabilities	67,841	121,794	398	—	190,033
Total liabilities	7,496,803	1,691,086	182,411	(2,633,356)	6,736,944
Stockholders' equity	2,253,249	7,714,708	26,881	(7,741,589)	2,253,249
Total liabilities and stockholders' equity	$9,750,052	$9,405,794	$209,292	$(10,374,945)	$8,990,193

Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2014

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Cash provided by (used in) operating activities	$(324,688)	$ 305,048	$(13,942)	$—	$ (33,582)
Investing Activities					
Capital expenditures	(2,700)	(144,586)	—	—	(147,286)
Additions to prepaid royalties	—	(7,317)	—	—	(7,317)
Proceeds from disposals and divestitures	57,625	4,733	—	—	62,358
Purchases of short term investments	(211,929)	—	—	—	(211,929)
Proceeds from sales of short term investments	205,611	—	—	—	205,611
Proceeds from sales of investments in equity securities	9,464	—	—	—	9,464
Investments in and advances to affiliates	(2,541)	(14,116)	—	—	(16,657)
Cash provided by (used in) investing activities	55,530	(161,286)	—	—	(105,756)
Financing Activities					
Payments on term loan	(19,500)	—	—	—	(19,500)
Net payments on other debt	(1,258)	(4,437)	—	—	(5,695)
Debt financing costs	(2,219)	—	(2,300)	—	(4,519)
Dividends paid	(2,123)	—	—	—	(2,123)
Other	(15)		(5,678)		(5,693)
Transactions with affiliates, net	67,125	(89,385)	22,260	—	—
Cash provided by (used in) financing activities	42,010	(93,822)	14,282	—	(37,530)
Increase (decrease) in cash and cash equivalents	(227,148)	49,940	340	—	(176,868)
Cash and cash equivalents, beginning of period	799,333	100,418	11,348	—	911,099
Cash and cash equivalents, end of period	$ 572,185	$ 150,358	$ 11,688	$—	$ 734,231

Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2013

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Cash provided by (used in) operating activities	$(632,060)	$ 637,193	$ 50,609	$ —	$ 55,742
Investing Activities					
Capital expenditures	(3,320)	(293,664)	—	—	(296,984)
Additions to prepaid royalties	—	(14,947)	—	—	(14,947)
Proceeds from disposals and divestitures	—	433,453	—	—	433,453
Proceeds from sales-leaseback transactions	—	34,919	—	—	34,919
Purchases of short term investments	(213,726)	—	—	—	(213,726)
Proceeds from sales of short term investments	194,537	—	—	—	194,537
Investments in and advances to affiliates	(5,451)	(10,321)	—	512	(15,260)
Change in restricted cash	3,453	—	—	—	3,453
Cash provided by (used in) investing activities	(24,507)	149,440	—	512	125,445
Financing Activities					
Contributions from parent	—	512	—	(512)	—
Proceeds from term loan and senior notes	644,000	—	—	—	644,000
Payments to retire debt	(628,660)	—	—	—	(628,660)
Payments on term loan	(17,250)	—	—	—	(17,250)
Net payments on other debt	(6,324)	(512)	—	—	(6,836)
Debt financing costs	(19,864)	—	(625)	—	(20,489)
Dividends paid	(25,475)	—	—	—	(25,475)
Transactions with affiliates, net	838,160	(786,683)	(51,477)	—	—
Cash provided by (used in) financing activities	784,587	(786,683)	(52,102)	(512)	(54,710)
Increase (decrease) in cash and cash equivalents	128,020	(50)	(1,493)	—	126,477
Cash and cash equivalents, beginning of period	671,313	100,468	12,841	—	784,622
Cash and cash equivalents, end of period	$ 799,333	$ 100,418	$ 11,348	$ —	$ 911,099

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

Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2012

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Cash provided by (used in) operating activities	$ (571,576)	$ 781,551	$ 122,829	$ —	$ 332,804
Investing Activities					
Change in restricted cash	6,869	—	—	—	6,869
Capital expenditures	(4,424)	(390,801)	—	—	(395,225)
Proceeds from disposals and divestitures	—	1,328	21,497	—	22,825
Investments in and advances to affiliates	(6,287)	(13,134)	—	1,663	(17,758)
Purchases of short term investments	(236,862)	—	—	—	(236,862)
Proceeds from sales of short term investments	1,754	—	—	—	1,754
Purchase of noncontrolling interest	(17,500)	—	—	—	(17,500)
Additions to prepaid royalties	—	(13,269)	—	—	(13,269)
Cash provided by (used in) investing activities	(256,450)	(415,876)	21,497	1,663	(649,166)
Financing Activities					
Contributions from parent	—	1,663	—	(1,663)	—
Proceeds from term loan and senior notes	1,993,253	—	—	—	1,993,253
Payments to retire debt	—	(452,934)	—	—	(452,934)
Net decrease in borrowings under lines of credit and commercial paper program	(375,000)	—	(106,300)	—	(481,300)
Payments on term loan	(7,625)	—	—	—	(7,625)
Net payments on other debt	(682)	—	—	—	(682)
Debt financing costs	(50,022)	—	(546)	—	(50,568)
Dividends paid	(42,440)	—	—	—	(42,440)
Issuance of common stock under incentive plans	5,131	—	—	—	5,131
Transactions with affiliates, net	(84,651)	110,639	(25,988)	—	—
Cash provided by (used in) financing activities	1,437,964	(340,632)	(132,834)	(1,663)	962,835
Increase in cash and cash equivalents	609,938	25,043	11,492	—	646,473
Cash and cash equivalents, beginning of period	61,375	75,425	1,349	—	138,149
Cash and cash equivalents, end of period	$ 671,313	$ 100,468	$ 12,841	$ —	$ 784,622

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)		
Year ended December 31, 2013					
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
Year ended December 31, 2013					
Reserves deducted from asset accounts:					
Accounts receivable and other receivables	$ 1,043	$ 346	$ —	$ 614	$ 775
Current assets—supplies and inventory	12,589	503	(2,274)[b]	2,372	8,446
Deferred income taxes	34,663	8,659	—	—	43,322
Year ended December 31, 2012					
Reserves deducted from asset accounts:					
Accounts receivable and other receivables	$ 17	$ 1,039	$ —	$ 13	$ 1,043
Current assets—supplies and inventory	13,107	1,961	—	2,479	12,589
Deferred income taxes	2,831	31,832	—	—	34,663

(a) Reserves utilized, unless otherwise indicated.

(b) Disposition of subsidiaries

Arch Coal, Inc. and Subsidiaries
Reconciliation of Non-GAAP Measures
(In thousands, except per share data)

This annual reportcontains non-GAAP measures as defined under Regulation G of the Securities Exchange Act of 1934, as amended. The reconciliation of these non-GAAP measures to the most comparable GAAP financial measures is presented below.

Adjusted EBITDA

Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization, and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results.

Adjusted EBITDA is not a measure of financial performance in accordance with generally accepted accounting principles, and items excluded from Adjusted EBITDA are significant in understanding and assessing our financial condition. Therefore, Adjusted EBITDA 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. We believe that Adjusted EBITDA presents a useful measure of our ability to incur and service debt based on ongoing operations. Furthermore, analogous measures are used by industry analysts to evaluate our operating performance. In addition, acquisition related expenses are excluded to make results more comparable between periods. Investors should be aware that our presentation of Adjusted EBITDA may not be comparable tosimilarly titled measures used by other companies. The table below shows how we calculate Adjusted EBITDA.

	Year Ended December 31,			
	2014	2013		
	Total Company	Continuing Operations	Discontinued Operations	Total Company
		(Unaudited)		
Net income (loss)	$(558.4)	$(745.2)	103.4	$(641.8)
Income tax (benefit) expense	25.6	(335.5)	49.1	(286.4)
Interest expense, net	383.2	374.7	—	374.7
Depreciation, depletion and amortization	418.8	426.4	21.3	447.7
Amortization of acquired sales contracts, net	(13.2)	(9.5)	—	(9.5)
Earnings before Interest, Taxes and DD&A (EBITDA)	256.0	(289.1)	173.8	(115.3)
Adjustments:				
Asset impairment and mine closure costs	24.1	220.9	—	220.9
Goodwill impairment	—	265.4	—	265.4
Settlement of UMWA legal claims	—	12.0	—	12.0
Other nonoperating expenses	—	42.9	—	42.9
Net income attributable to noncontrolling interest	—	—	—	—
Total adjustments	24.1	541.2	—	541.2
Adjusted EBITDA	$ 280.1	$ 252.1	$173.8	$ 425.9

Adjusted net loss and adjusted diluted loss per share

Adjusted net loss and adjusted diluted loss per common share are adjusted for the after-tax impact of acquisition related costs and are not measures of financial performance in accordance with generally accepted accounting principles. We believe that adjusted net loss and adjusted diluted loss per common share better reflect the trend of our future results by excluding items relating to significant transactions. The adjustments made to arrive at these measures are significant in understanding and assessing our financial condition. Therefore, adjusted net loss and adjusted diluted loss per share should not be considered in isolation, nor as an alternative to net loss or diluted loss per common share under generally accepted accounting principles.

	Year Ended December 31,		
	2014	**2013**	**2012**
Net loss attributable to Arch Coal	$(558.4)	$(641.8)	$(684.0)
Sales contract amortization	(13.2)	(9.5)	(25.2)
Other adjustment items listed above	24.1	541.2	893.7
Tax impact of adjustments	(3.9)	(119.1)	(261.2)
Adjusted net loss attributable to Arch Coal	$(551.4)	$(229.2)	$ (76.7)
Diluted weighted average shares outstanding	212.2	212.1	211.4
Diluted loss per share attributable to Arch Coal	$ (2.63)	$ (3.03)	$ (3.24)
Sales contract amortization	$ (0.06)	$ (0.04)	$ (0.12)
Other adjustments	$ 0.11	$ 2.55	$ 4.23
Tax impact of adjustments	$ (0.02)	$ (0.56)	$ (1.24)
Adjusted diluted loss per share	$ (2.60)	$ (1.08)	$ (0.36)

As of February 27, 2015

Board of Directors

John W. Eaves (c) (e)
President and Chief Executive Officer, Arch Coal, Inc.

David D. Freudenthal (d) (e*)
Senior Counsel, Crowell & Moring, LLC; former Governor, State of Wyoming

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Senior Counsel, Van Ness Feldman

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J. Thomas Jones (c) (d*)
Former Chief Executive Officer, West Virginia United Health System

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Executive Vice President and Chief Operating Officer, Arch Coal, Inc.

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Former President, TXU Generation

Peter I. Wold (a) (e)
President, Wold Oil Properties, LLC; Director, Oppenheimer Funds, Inc. New York Board

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(b) Nominating and Corporate Governance Committee
(c) Finance Committee
(d) Personnel and Compensation Committee
(e) Energy and Environmental Policy Committee
* Committee Chair

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Paul A. Lang
Executive Vice President and Chief Operating Officer

John T. Drexler
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Senior Vice President, Operations

Robert G. Jones
Senior Vice President—Law, General Counsel and Secretary

Allen R. Kelley
Vice President, Human Resources

Deck S. Slone
Senior Vice President, Strategy and Public Policy

John A. Ziegler, Jr.
Chief Commercial Officer

ARCH COAL, INC. SHAREHOLDER INFORMATION

COMMON STOCK
Our common stock is listed and traded on the New York Stock Exchange under the ticker symbol ACI. On February 13, 2015, our common stock closed at $1.19 and we had approximately 5,500 holders of record of our common stock on that date.

DIVIDENDS
Arch paid dividends on our common stock totaling $0.01 per share in 2014. In 2015, we announced that we would not pay a dividend. There is no assurance as to the amount or payment of dividends in future periods because they are dependent on our future earnings, capital requirements and financial condition.

CODE OF BUSINESS CONDUCT
We operate under a code of business conduct that applies to all of our salaried employees, including our chief executive officer, chief financial officer and chief accounting officer. The code is published under "Corporate Governance" at investor.archcoal.com.

CORPORATE GOVERNANCE GUIDELINES
Our board of directors has adopted corporate governance guidelines that address various matters pertaining to director selection and duties. The guidelines are published under "Corporate Governance" at http://investor.archcoal.com.

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St. Louis, Missouri 63105

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Questions regarding shareholder records, stock transfers, stock certificates, dividends, the Dividend Reinvestment and Direct Stock Purchase Plan, or other stock inquiries should be directed to:
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