CLOUD PEAK ENERGY INC.
Form 10-K
February 18, 2015
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-K

(Mark One)

x 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

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

For the transition period from to

Commission File Number: 001-34547

Cloud Peak Energy Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**26-3088162** (I.R.S. Employer Identification No.)
505 S. Gillette Ave., Gillette, Wyoming (Address of Principal Executive Offices)	**82716** (Zip Code)

(307) 687-6000
(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	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 o No x

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 o No x

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

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

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

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o
(Do not check if a 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 o No x

As of June 30, 2014, the last business day of Cloud Peak Energy Inc. s most recently completed second fiscal quarter, the aggregate market value of the voting and nonvoting common stock held by non-affiliates of Cloud Peak Energy Inc. was approximately $1,122 million based on the closing price of Cloud Peak Energy Inc. s common stock as reported that day on the New York Stock Exchange of $18.42 per share. In determining this figure, Cloud Peak Energy Inc. has assumed that all of its directors and executive officers are affiliates. Such assumptions should not be deemed conclusive for any other purpose.

Number of shares outstanding of Cloud Peak Energy Inc. s common stock, as of the latest practicable date: Common stock, $0.01 par value per share, 61,021,242 shares outstanding as of February 11, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Cloud Peak Energy Inc. s proxy statement to be filed with the Securities and Exchange Commission in connection with Cloud Peak Energy Inc. s 2015 annual meeting of stockholders (the Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

Table of Contents

CLOUD PEAK ENERGY INC.

TABLE OF CONTENTS

Explanatory Note

On March 25, 2014, Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp. (together with Cloud Peak Energy Resources, the Issuers), Cloud Peak Energy Inc., Wilmington Trust Company, as trustee, and Citibank N.A., as securities administrator, entered into the fifth supplemental indenture (the Fifth Supplemental Indenture) to the indenture governing the Issuers 8.250% Senior Notes due 2017 (which are no longer outstanding) and 8.500% Senior Notes due 2019 (collectively, the Notes). Pursuant to the Fifth Supplemental Indenture, Cloud Peak Energy Inc. has agreed to guarantee the Notes and to be bound by the terms of the indenture governing the Notes applicable to guarantors. As a result of such guarantee, and pursuant to Rule 12h-5 promulgated under the Securities Exchange Act of 1934 (Exchange Act) and Rule 3-10 of Regulation S-X, Cloud Peak Energy Resources LLC is no longer required to file reports under Section 15(d) of the Exchange Act and has filed a Form 15 in connection therewith.

Unless the context indicates otherwise, the terms Cloud Peak Energy, the Company, we, us, and our refer to Cloud Peak Energy Inc. and its subsidiaries.

Table of Contents

CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that involve substantial risks and uncertainties. You can identify these statements by forward-looking words such as anticipate, believe, could, estimate, expect, intend, may, plan, potential, should, will, wou
You should read statements that contain these words carefully because they discuss our current plans, strategies, prospects, and expectations concerning our business, operating results, financial condition, and other similar matters. While we believe that these forward-looking statements are reasonable as and when made, there may be events in the future that we are not able to predict accurately or control, and there can be no assurance that future developments affecting our business will be those that we anticipate. Additionally, all statements concerning our expectations regarding future operating results are based on current forecasts for our existing operations and do not include the potential impact of any future acquisitions. The factors listed under Risk Factors, as well as any cautionary language in this report, describe the known material risks, uncertainties, and events that may cause our actual results to differ materially and adversely from the expectations we describe in our forward-looking statements. Additional factors or events that may emerge from time to time, or those that we currently deem to be immaterial, could cause our actual results to differ, and it is not possible for us to predict all of them. You are cautioned not to place undue reliance on the forward-looking statements contained herein. We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events, or otherwise, except as required by law. The following factors are among those that may cause actual results to differ materially and adversely from our forward-looking statements:

- the prices we receive for our coal and logistics services, our ability to effectively execute our forward sales strategy, and changes in utility purchasing patterns;

- competition with other producers of coal, including the current oversupply of thermal coal in the marketplace, impacts of currency exchange rate fluctuations, and government energy and tax policies that make foreign coal producers more competitive for international transactions;

- competition with natural gas and other non-coal energy resources, which may be increased as a result of energy and tax policies, regulations and subsidies or other government incentives that encourage or mandate use of alternative energy sources;

- coal-fired power plant capacity, including the impact of climate change or other environmental regulations, energy policies, political pressures, NGO activities, and other factors that may cause domestic and international electric utilities to continue to phase out or close existing coal-fired power plants, reduce or eliminate construction of any new coal-fired power plants, or reduce consumption of PRB coal;

- the failure of economic, commercially available carbon capture technology to be developed and adopted in a timely manner;

- market demand for domestic and foreign coal, electricity and steel;

- our ability to grow our logistics revenue and export sales at favorable prices;
- railroad, export terminal and other transportation performance, costs and availability, including the availability of sufficient and reliable rail capacity to transport PRB coal and the development of additional export terminal capacity, our ability to access additional capacity on commercially reasonable terms, and the impact of rail and terminal take-or-pay commitments;
- domestic and international economic conditions;
- timing of reductions or increases in customer coal inventories;
- weather conditions or weather-related damage that impacts demand for coal, our mining operations, our customers, or transportation infrastructure;
- risks inherent to surface coal mining;
- our ability to successfully acquire coal and appropriate land access rights at attractive prices and in a timely manner and our ability to effectively resolve issues with conflicting mineral development that may impact our mine plans;
- our ability to produce coal at existing and planned volumes and to effectively manage the costs of our operations;
- the impact of asset impairment charges if required as a result of challenging industry conditions or other factors;
- our plans and objectives for future operations and the development of additional coal reserves, including risks associated with acquisitions;

Table of Contents

- the impact of current and future environmental, health, safety and other laws, regulations, treaties or governmental policies, or changes in interpretations thereof, and third-party regulatory challenges, including those affecting our coal mining operations (such as the potential listing of the greater sage-grouse as a threatened species) or our customers coal usage, carbon and other gaseous emissions or ash handling, or the logistics, transportation, or terminal industries, as well as related costs and liabilities;

- the impact of required regulatory processes and approvals to lease and obtain permits for coal mining operations or to transport coal to domestic and foreign customers, including third-party legal challenges;

- any increases in rates or changes in regulatory interpretations or assessment methodologies with respect to royalties or severance and production taxes and the potential impact of associated interest and penalties;

- inaccurately estimating the costs or timing of our reclamation and mine closure obligations;

- our ability to obtain required surety bonds and provide any associated collateral on commercially reasonable terms;

- disruptions in delivery or increases in pricing from third-party vendors of raw materials and other consumables which are necessary for our operations, such as explosives, petroleum-based fuel, tires, steel, and rubber;

- our assumptions concerning coal reserve estimates;

- our relationships with, and other conditions affecting, our customers (including our largest customers who account for a significant portion of our total revenue) and other counterparties, including economic conditions and the credit performance and credit risks associated with our customers and other counterparties, such as traders, brokers, and lenders under our credit agreement and financial institutions with whom we maintain accounts or enter hedging arrangements;

- the results of our hedging strategies for commodities, including our current hedging programs for domestic and international coal sales and diesel fuel costs;

- the terms and restrictions of our indebtedness;

- liquidity constraints, including those resulting from the cost or unavailability of financing due to credit market conditions, changes in our credit rating, or our compliance with the covenants in our debt agreements;

- our liquidity, results of operations, and financial condition generally, including amounts of working capital that are available; and

- other factors, including those discussed in Item 1A of this Form 10-K.

Table of Contents

GLOSSARY FOR SELECTED TERMS

Anthracite. Anthracite is the highest rank coal. It is hard, shiny (or lustrous), has a high heat content, and little moisture. Anthracite is used in residential and commercial heating as well as a mix of industrial applications. Some waste products from anthracite piles are used in energy generation.

Ash. Inorganic material consisting of iron, alumina, sodium, and other incombustible matter that remain after the combustion of coal. The composition of the ash can affect the burning characteristics of coal.

Assigned reserves. Reserves that are committed to our surface mine operations with operating mining equipment and plant facilities. All our reported reserves are considered to be assigned reserves.

Bituminous coal. The most common type of coal that is between subbituminous and anthracite in rank. Bituminous coal produced from the central and eastern U.S. coal fields typically have moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btus.

BLM. Department of the Interior, Bureau of Land Management.

BNSF. Burlington Northern Santa Fe Railroad.

Btu. British thermal unit. A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

CAIR. Clean Air Interstate Rule.

CO2. Carbon dioxide. A gaseous chemical compound that is generated, among other ways, as a by-product of the combustion of fossil fuels, including coal, or the burning of vegetable matter.

CPE Inc. Cloud Peak Energy Inc., a Delaware corporation.

CPE Resources. Cloud Peak Energy Resources LLC, a Delaware limited liability company, formerly known as Rio Tinto Sage LLC, which is the sole direct subsidiary of CPE Inc.

Coal seam. Coal deposits occur in layers typically separated by layers of rock. Each layer is called a seam. A coal seam can vary in thickness from inches to a hundred feet or more.

Coalbed methane. Also referred to as CBM or coalbed natural gas (CBNG). Coalbed methane is methane gas formed during the coalification process and stored within the coal seam.

Coke. A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel.

Compliance coal. Coal that when combusted emits no greater than 1.2 pounds of sulfur dioxide per million Btus and requires no blending or sulfur-reduction technology to comply with current sulfur dioxide emissions under the Clean Air Act.

CSAPR. Cross-State Air Pollution Rule.

Dragline. A large excavating machine used in the surface mining process to remove overburden. A dragline has a large bucket suspended from the end of a boom, which may be 275 feet long or larger. The bucket is suspended by cables and capable of scooping up significant amounts of overburden as it is pulled across the excavation area. The dragline, which can walk on large pontoon-like feet, is one of the largest land-based machines in the world.

EIA. Energy Information Administration.

EIS. Environmental Impact Statement.

EPA. United States Environmental Protection Agency.

Table of Contents

Force majeure. An event not anticipated as of the date of the applicable contract, which is not within the reasonable control of the party affected by such event, which partially or entirely prevents such party s ability to perform its contractual obligations. During the duration of such force majeure but for no longer period, the obligations of the party affected by the event may be excused to the extent required.

Fossil fuel. A hydrocarbon such as coal, petroleum, or natural gas that may be used as a fuel.

GHG. Greenhouse gas.

GW. Gigawatts.

Highwalls. The unexcavated face of exposed overburden and coal in a surface mine.

IR. Incident rate. The rate of injury occurrence, as determined by MSHA, based on 200,000 hours of employee exposure and calculated as follows:

IR = (number of cases x 200,000) / hours of employee exposure.

LBA. Lease by Application. Before a mining company can obtain new coal leases on federal land, the company must nominate lands for lease. The BLM then reviews the proposed tract to ensure maximum coal recovery. The BLM also requires completion of a detailed environmental assessment or an EIS, and then schedules a competitive lease sale. Lease sales must meet fair market value as determined by the BLM. The process is known as Lease by Application. After a lease is awarded, the BLM also has the responsibility to assure development of the resource is conducted in a fashion that achieves maximum economic recovery.

LBM. Lease by Modification. A process of acquiring federal coal through a non-competitive leasing process. An LBM is used in circumstances where a lessee is seeking to modify an existing federal coal lease by adding less than 960 acres in a configuration that is deemed non-competitive to other coal operators.

Lbs SO2/mmBtu. Pounds of sulfur dioxide emitted per million Btu of heat generated.

Lignite. The lowest rank of coal. It is brownish-black with a high moisture content commonly above 35% by weight and heating value commonly less than 8,000 Btu.

LMU. Logical Mining Unit. A combination of contiguous federal coal leases that allows the production of coal from any of the individual leases within the LMU to be used to meet the continuous operation requirements for the entire LMU.

MATS. Mercury and Air Toxics Standards (formerly Utility Maximum Achievable Control Technology, or Utility MACTS).

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as met coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Metallurgical coal has a particularly high Btu, but low ash content.

MSHA. Mine Safety and Health Administration.

NAAQ. National Ambient Air Quality.

NGO. Non-governmental organization.

NOx. Nitrogen oxides. NOx represents both nitrogen dioxide (NO_2) and nitrogen trioxide (NO_3), which are gases formed in high temperature environments, such as coal combustion. It is a harmful pollutant that contributes to acid rain and is a precursor of ozone.

Non-reserve coal deposits. Non-reserve coal deposits are coal bearing bodies that have been sufficiently sampled and analyzed in trenches, outcrops, drilling, and underground workings to assume continuity between sample points, and therefore warrant further exploration work. However, this coal does not qualify as commercially viable coal reserves as prescribed by the Securities and Exchange Commission, or SEC, standards until a final comprehensive evaluation based on unit cost per ton, recoverability, and other material factors concludes legal and economic feasibility. Non-reserve coal deposits may be classified as such by either limited property control or geologic limitation, or both.

QSO. Qualified Surface Owner. A status attributed by the BLM to a certain class of surface owners of split estate lands which allows the QSO to prohibit leasing of federal coal without their explicit consent.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

PRB. Powder River Basin. Coal producing area in northeastern Wyoming and southeastern Montana.

Preparation plant. Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing, and washing coal to prepare it for use by a particular customer. The washing process separates higher ash coal and may also remove some of the coal s sulfur content.

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. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

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 process of restoring land to its prior condition, productive use, or other permitted condition following mining activities. The process commonly includes recontouring or reshaping the land to its approximate original appearance, restoring topsoil, and planting native grass and shrubs. Reclamation operations are typically conducted concurrently with coal mining operations. Reclamation is closely regulated by both state and federal laws.

Reserve. That part of a mineral deposit that could be economically and legally extracted or produced at the time of the reserve determination.

Rio Tinto. Rio Tinto plc and Rio Tinto Limited and their direct and indirect subsidiaries, including Rio Tinto Energy America Inc. (RTEA), our predecessor for accounting purposes; Kennecott Management Services Company (KMS); and Rio Tinto America Inc. (RTA), which is the owner of RTEA and KMS.

Riparian habitat. Areas adjacent to rivers and streams with a differing density, diversity, and productivity of plant and animal species relative to nearby uplands.

Riverine habitat. A habitat occurring along a river.

Scrubber. Any of several forms of chemical physical devices which operate to control sulfur compounds formed during coal combustion. An example of a scrubber is a flue gas desulfurization unit.

SMCRA. Surface Mining Control and Reclamation Act of 1977.

Spoil-piles. Pile used for any dumping of waste material or overburden material, particularly used during the dragline method of mining.

Subbituminous coal. Black coal that ranks between lignite and bituminous coal. Subbituminous coal produced from the PRB has a moisture content between 20% to over 30% by weight, and its heat content ranges from 8,000 to 9,500 Btus.

Sulfur. One of the elements present in varying quantities in coal. Sulfur dioxide (SO_2) is produced as a gaseous by-product of coal combustion.

Table of Contents

Sulfur dioxide emission allowance. A tradable authorization to emit sulfur dioxide. Under Title IV of the Clean Air Act, one allowance permits the emission of one ton of sulfur dioxide.

Surface mine. A mine in which the coal lies near the surface and can be extracted by removing the covering layer of soil overburden. Surface mines are also known as open-pit mines.

Tax agreement liability. The undiscounted estimated future liability previously owed by CPE Inc. to Rio Tinto under the Tax Receivable Agreement.

Thermal coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Tonnes. A metric ton, equal to 2,205 pounds.

Tons. A short or net ton, equal to 2,000 pounds.

TRA. Tax Receivable Agreement. We and RTEA entered into a Tax Receivable Agreement in connection with the IPO and the acquisition of our membership units of CPE Resources. The Tax Receivable Agreement required us to pay to RTEA 85% of the amount of cash tax savings, if any, that we realized as a result of the increases in tax basis that we obtained in connection with the initial acquisition of our interest in CPE Resources and our subsequent acquisition of RTEA s remaining units in CPE Resources. In August 2014, we entered into an acceleration and release agreement with Rio Tinto whereby we agreed to pay $45 million to Rio Tinto to terminate the Tax Receivable Agreement.

Truck-and-shovel mining. Similar forms of mining where large shovels or front-end loaders are used to remove overburden, which is used to backfill pits after the coal is removed. Smaller shovels load coal in haul trucks for transportation to the preparation plant or rail loading facilities.

UP. Union Pacific Railroad.

Table of Contents

PART I

Item 1. *Business.*

Overview

We are one of the largest producers of coal in the United States of America (U.S.) and the PRB, based on our 2014 coal sales. We operate some of the safest mines in the coal industry. According to the most current MSHA data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies.

We currently operate solely in the PRB, the lowest cost region of the major coal producing regions in the U.S., where we operate three 100% owned surface coal mines, the Antelope Mine, the Cordero Rojo Mine and the Spring Creek Mine. We also have two major development projects, the Youngs Creek project and the Crow project. On September 12, 2014, we completed the sale of our 50% non-operating interest in Decker Coal Company (Decker Mine) to an affiliate of Ambre Energy North America, Inc. (Ambre Energy). For further information regarding this transaction, please see Note 4 of Notes to Consolidated Financial Statements in Item 8.

Our Antelope Mine and Cordero Rojo Mine are located in Wyoming and our Spring Creek Mine is located in Montana. Our mines produce subbituminous thermal coal with low sulfur content, and we sell our coal primarily to domestic and foreign electric utilities. We do not produce any metallurgical coal. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation and steam output. In 2014, the coal we produced generated approximately 4% of the electricity produced in the U.S. As of December 31, 2014, we controlled approximately 1.1 billion tons of proven and probable reserves.

In 2012, we acquired the Youngs Creek project. It is a permitted but undeveloped surface mine project in the Northern PRB region located 13 miles north of Sheridan, Wyoming, contiguous with the Wyoming-Montana state line. The Youngs Creek project is approximately seven miles south of our Spring Creek Mine and seven miles from the mainline railroad, and is near the Crow project. We have not yet been able to classify the Youngs Creek project mineral rights as proven and probable reserves as they remain subject to further exploration and evaluation. In 2013, we entered an option to lease agreement and a corresponding exploration agreement with the Crow Tribe of Indians. This coal project (Crow project) is located on the Crow Indian Reservation in southeast Montana. We are in the process of evaluating the development options for the Youngs Creek project and the Crow project and believe that their proximity to the Spring Creek Mine represents an opportunity to optimize our mine developments in the Northern PRB. For purposes of this report, the term Northern PRB refers to the area within the PRB that lies within Montana and the northern part of Sheridan County, Wyoming.

We continue to develop our sales of PRB coal and delivery services business into the Asian export market. In 2014, our logistics business was the largest U.S. exporter of thermal coal into South Korea. We continue to seek ways to increase our future export capacity through existing and proposed Pacific Northwest export terminals. In August 2014, we paid $37.0 million to secure additional committed capacity at the fully-utilized Westshore Terminals Limited Partnership port (Westshore), in British Columbia. As a result, we increased our long-term committed capacity from 2.8 million tons to 6.3 million tons initially and increasing to 7.2 million tons in 2019 and extended the term of our throughput agreement by two years through the end of 2024. In early 2015, as current international prices remain low, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons, thereby reducing our committed 2015 capacity at

Westshore to 5.8 million tons. For further information regarding this transaction, please see Note 9 of Notes to Consolidated Financial Statements in Item 8.

As part of the Decker Mine divestiture transaction, we were granted a throughput option for up to 7.7 million tons per year at the proposed Millennium Bulk Terminals coal export facility in Washington State. The proposed new coal export facility is currently in the permitting stage and is planned to be developed in two phases. Our option covers up to 3.3 million tons per year of capacity during the first phase of development and an additional 4.4 million tons per year once the second phase of development is reached. Our throughput capacity will have an initial term of 10 years, with four renewal options for five-year terms. Our option is exercisable following the successful completion of the ongoing permit process, which is currently in the EIS phase. The timing and outcome of the permit process are uncertain.

We also have a throughput option agreement with SSA Marine, which provides us with an option for up to 17.6 million tons of capacity per year through the planned dry bulk cargo Gateway Pacific Terminal at Cherry Point in Washington State. Our potential share of capacity will depend upon the ultimate capacity of the terminal and is subject to the terms of the option agreement. The terminal will accommodate cape size vessels. Our option is exercisable following the

Table of Contents

successful completion of the ongoing permit process, which is currently in the EIS phase. The timing and outcome of the permit process are uncertain.

For information regarding our revenue and long-lived assets by geographic area, as well as revenue from external customers, Adjusted EBITDA and total assets by segment, please see Note 24 of Notes to Consolidated Financial Statements in Item 8.

Segment Information

We have reportable segments of Owned and Operated Mines, Logistics and Related Activities, and Corporate and Other.

Our Owned and Operated Mines segment is characterized by the predominant focus on thermal coal production where the sale occurs at the mine site and where title and risk of loss pass to the customer at that point. This segment includes our Antelope Mine, Cordero Rojo Mine, and Spring Creek Mine. Sales in this segment are primarily to domestic electric utilities; although a portion is made to our Logistics and Related Activities segment. Sales between reportable segments are priced based on prevailing market prices. Our mines utilize surface mining extraction processes and are all located in the PRB. The gains and losses resulting from our domestic coal futures contracts and West Texas Intermediate (WTI) derivative financial instruments are reported within this segment.

Our Logistics and Related Activities segment is characterized by the services we provide to our international and domestic customers where we deliver coal to the customer at a terminal or the customer s plant or other delivery point, remote from our mine site. Services provided include the purchase of coal from third parties or from our owned and operated mines, at market prices, as well as the contracting and coordination of the transportation and other handling services from third-party operators, which are typically rail and terminal companies. Title and risk of loss are retained by the Logistics and Related Activities segment through the transportation and delivery process. Title and risk of loss pass to the customer in accordance with the contract and typically occur at a vessel loading terminal, a vessel unloading terminal or an end use facility. Risk associated with rail and terminal take-or-pay agreements is also borne by the Logistics and Related Activities segment. The gains and losses resulting from our international coal forward derivative financial instruments are reported within this segment. Port access contract rights and related amortization are also included in this segment.

Our Corporate and Other segment includes results relating to broker activity, our previous share of the Decker Mine operations, which was sold on September 12, 2014, and unallocated corporate costs and assets. All corporate costs, except Board of Directors related expenses, are allocated to the segments based upon their relative percentage of certain financial metrics.

Eliminations represent the purchase and sale of coal between reportable segments and the associated elimination of intercompany profit or loss in inventory.

History

CPE Inc., a Delaware corporation organized on July 31, 2008, is a holding company that manages its 100% owned consolidated subsidiary CPE Resources, but has no business operations or material assets other than its ownership interest in CPE Resources. CPE Inc. s only source of cash flow from operations is distributions from CPE Resources pursuant to the CPE Resources limited liability company agreement. CPE Inc. also receives management fees pursuant to a management services agreement between CPE Inc. and CPE Resources as reimbursement of certain administrative expenses.

Our business operations are conducted by CPE Resources, formerly known as Rio Tinto Sage LLC, a Delaware limited liability company formed as a 100% owned subsidiary of RTEA on August 19, 2008. RTEA is our predecessor for accounting purposes. RTEA, a Delaware corporation, formerly known as Kennecott Coal Company, was formed as a 100% owned subsidiary of RTA on March 1, 1993. Between 1993 and 1998, RTEA acquired the Antelope Mine, Colowyo Mine, Jacobs Ranch Mine and Spring Creek Mine and the Cordero and Caballo Rojo coal mines, which are operated together as the Cordero Rojo Mine, and a 50% non-operating interest in the Decker Mine. In December 2008, RTEA contributed RTA s western U.S. coal business to CPE Resources (other than the Colowyo Mine). On October 1, 2009, CPE Resources sold the Jacobs Ranch Mine to Arch Coal, Inc. and distributed the proceeds to Rio Tinto and on September 12, 2014, we sold our 50% interest in the Decker Mine to Ambre Energy.

CPE Inc. acquired approximately 51% and the managing member interest in CPE Resources in exchange for a promissory note which was repaid with proceeds from the initial public offering of its common stock (IPO) on November

19, 2009. Rio Tinto retained ownership of the remaining 49% until December 15, 2010, when CPE Inc. priced a secondary offering of its common stock on behalf of Rio Tinto. In connection with the secondary offering, CPE Inc. exchanged shares of common stock for the 49% common membership units of CPE Resources held by Rio Tinto and completed the secondary offering on behalf of Rio Tinto (the Secondary Offering), resulting in our acquisition of 100% of Rio Tinto s holdings in CPE Resources. As a result of this transaction, CPE Resources became a 100% owned subsidiary of CPE Inc., and Rio Tinto no longer holds an interest in CPE Resources.

Coal Characteristics

In general, coal of all geological compositions is characterized by end use either as thermal or metallurgical. Heat value and sulfur content are the most important variables in the economic marketing and transportation of thermal coal. We mine, process, and market low sulfur content, subbituminous thermal coal, the characteristics of which are described below. Because we currently operate only in the PRB, which does not have metallurgical coal, we produce only thermal coal.

Heat Value

The heat value of coal is commonly measured in Btus. Subbituminous coal from the PRB has a typical heat value that ranges from 8,000 to 9,500 Btus. Subbituminous coal from the PRB is used primarily by electric utilities and by some industrial customers for steam generation. Coal found in other regions in the U.S., including the eastern and Midwestern regions, tends to have a higher heat value than coal found in the PRB, other than lignite coal which has lower heat value than subbituminous coal but is typically only used to supply coal to utilities that are directly adjacent to the mine.

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. See Environmental and Other Regulatory Matters Clean Air Act. The sulfur content of coal can vary from seam to seam and within a single seam. The concentration of sulfur in coal affects the amount of sulfur dioxide produced in combustion. Coal-fired power plants can comply with sulfur dioxide emissions 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-reduction technology, such as scrubbers, which can reduce sulfur dioxide emissions by up to 90%. According to the EPA, in 2013, out of utilities with a coal generating capacity of approximately 286 GW, utilities accounting for a capacity of over 203 GW had been retrofitted with scrubbers. The demand or price for lower sulfur coal may decrease with widespread implementation of sulfur-reduction technology.

PRB coal typically has a lower sulfur content than eastern U.S. coal and generally emits no greater than 1.2 pounds of sulfur dioxide per million Btus.

Other

Ash is the inorganic residue remaining after the combustion of coal. As with sulfur content, 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 ash content of PRB coal is generally low, representing approximately 5% to 10% by weight. The composition of the ash, including the proportion of sodium oxide, as well as the ash fusion temperatures are important characteristics of coal and help determine the suitability of the coal to specific end users. In limited cases, domestic customer requirements at the Spring Creek Mine have required, and may continue to require, the addition of earthen materials to dilute the sodium oxide content of the post-combustion ash of the coal.

Moisture content of coal varies by the type of coal and the region where it is mined. In general, high moisture content is associated with lower heat values and generally makes the coal more expensive to transport. Moisture content in coal, on an as-sold basis, can range from approximately 2% to over 35% of the coal s weight. PRB coals have typical moisture content of 20% to 30%.

Mercury and chlorine are trace elements within coal that are of primary consideration relative to utility plant emissions and performance. Trace amounts of mercury and chlorine in PRB coal are relatively low compared to coal from other regions.

Table of Contents

Coal Mining Methods

Surface Mining

All of our mines are surface mining operations utilizing both dragline and truck-and-shovel mining methods. Surface mining is used when coal is found relatively close to the surface. Surface mining typically involves the removal of topsoil and drilling and blasting the overburden with explosives. The overburden is then removed with draglines, trucks, shovels, and dozers. Trucks and shovels then remove the coal. The final step involves replacing the overburden and topsoil after the coal has been excavated, reestablishing vegetation into the natural habitat and making other changes designed to provide local community benefits. We typically recover 90% or more of the economic coal seam for the mines we operate.

Coal Preparation and Blending

In almost all cases, the coal from our mines is crushed and shipped directly from our mines to the customer. Typically, no other preparation is needed for a saleable product. However, depending on the specific quality characteristics of the coal and the needs of the customer, blending different types of coals may be required at the customer s plant. Coals of various sulfur and ash contents can be mixed or blended to meet the specific combustion and environmental needs of customers. All of our coal can be blended with coal from other coal producers. Spring Creek Mine s location and the high Btu content of its coal make its coal better suited than our other coal for export and transportation to the northeastern U.S. coal markets for blending by the customer with coal sourced from other markets to achieve a suitable overall product.

Mining Operations

We currently operate solely in the PRB. Two of the mines we operate are located in Wyoming and one is located in Montana. On September 12, 2014, we completed the sale of our 50% non-operating interest in the Decker Mine, which is located in Montana. We currently own the majority of the equipment utilized in our mining operations. We employ preventative maintenance and rebuild programs and upgrade our equipment as part of our efforts to ensure that it is productive, well-maintained, and cost-competitive. Our maintenance programs also utilize procedures designed to enhance the efficiencies of our operations. The following table provides summary information regarding our mines as of December 31, 2014.

[redacted]

Antelope	8,860	5.48	0.24	0.54	33.6	31.4	34.3
[redacted]							
Spring Creek	9,244	5.20	0.32	0.69	17.4	18.0	17.2
[redacted]							
Other(3)	N/A	N/A	N/A	N/A	0.2	1.5	0.9
[redacted]							

(1) We are reducing Cordero Rojo production to approximately 28 million tons per year starting in 2015.

(2) Tons sold numbers reflect our 50% non-operating interest through our September 12, 2014 divestiture.

(3) The tonnage shown for Other represents our purchases from third-party sources that we have resold. See Mining Operations Broker Sales and Third-Party Sources.

Our Owned and Operated Mines segment includes our Antelope Mine, Cordero Rojo Mine and Spring Creek Mine. Our Antelope and Cordero Rojo mines are served by the BNSF and UP railroads. Our Spring Creek Mine is served solely by the BNSF railroad.

Table of Contents

The following map shows the locations of our mining operations:

Antelope Mine

The Antelope Mine is located in the southern end of the PRB approximately 60 miles south of Gillette, Wyoming. The mine extracts thermal coal from the Anderson and Canyon Seams, with up to 44 and 36 feet, respectively, in thickness. Significant areas of unleased coal north and west of the mine are available for nomination by us or other mining operations or persons. Based on the average sulfur content of 0.50 lbs SO_2/mmBtu, the reserves at our Antelope Mine are considered to be compliance coal under the Clean Air Act, and this coal is some of the lowest sulfur coal produced in the PRB.

Cordero Rojo Mine

The Cordero Rojo Mine is located approximately 25 miles south of Gillette, Wyoming. The mine extracts thermal coal from the Wyodak Seam, which ranges from approximately 55 to 70 feet in thickness. We previously nominated as an LBA a large coal tract adjacent to our existing operation. The BLM divided this LBA into two tracts, Maysdorf II North and Maysdorf II South. The Maysdorf II North tract was offered in August 2013 and no bids were submitted. Our decision not to bid was made in light of market conditions and access issues to the coal. We understand that the BLM is expecting to delay any future lease sale on the Maysdorf II South tract until current weak markets improve. Significant additional areas of unleased coal are potentially available for nomination by us or other mining operations or persons adjacent to our current operations. Based on the average sulfur content of 0.69 lbs SO_2/mmBtu, the reserves at our Cordero Rojo Mine are considered to be compliance coal under the Clean Air Act.

Spring Creek Mine

The Spring Creek Mine is located in Montana approximately 20 miles north of Sheridan, Wyoming. The mine extracts thermal coal from the Anderson-Dietz Seam, which averages approximately 80 feet in thickness. The location of the mine relative to the Great Lakes is attractive to our customers in the northeast because of lower transportation costs. The location of the Spring Creek Mine also provides access to export terminals in the Pacific Northwest, providing a geographic advantage relative to other PRB mines. As a result, interest from Asian utilities in coal from our Spring Creek Mine and our logistics services continues, and in 2014, we shipped approximately 4.0 million tons of Spring Creek coal through terminals located in British Columbia, Canada. We continue to seek opportunities to increase our port capacity in the Pacific Northwest. Based on the average sulfur content of 0.73 lbs SO_2/mmBtu, the reserves at our Spring Creek Mine are considered to be compliance coal under the Clean Air Act.

Table of Contents

Development Projects

Youngs Creek Project

The Youngs Creek project is a permitted but undeveloped surface mine project in the Northern PRB region located 13 miles north of Sheridan, Wyoming, contiguous with the Wyoming-Montana state line. The Youngs Creek project is approximately seven miles south of our Spring Creek Mine and seven miles from the mainline railroad, and is near the Crow project (described below). We acquired the Youngs Creek project in June 2012. The coal located at the Youngs Creek project is similar quality to that of our Spring Creek Mine and offers lower sodium levels. The Youngs Creek project mining permit covers 287 million tons of non-reserve coal deposits, of which approximately 272 million tons benefit from a royalty rate of 8.0% of the coal sales price free on board (FOB) at the mine site, payable to the sellers, which is below the normal 12.5% royalty rate payable on federal coal. We also control additional leased and private coal related to the Youngs Creek project that has not yet been evaluated and is not yet in any mine plan. We also acquired approximately 38,800 acres of surface rights which includes land extending north to our Spring Creek Mine, and onto the Crow Indian Reservation to the west. We are in the process of evaluating the development options for this project and believe that its proximity to the Spring Creek Mine and the Crow project represent an opportunity to optimize our mine developments in the Northern PRB region.

Crow Project

In January 2013, we entered into an option agreement and a corresponding exploration agreement with the Crow Tribe of Indians. These agreements were approved by the Department of the Interior on June 14, 2013. This coal project is located on the Crow Indian Reservation in southeast Montana, near our Spring Creek Mine and Youngs Creek project in the Northern PRB region. In 2013, we paid the Crow Tribe $3.75 million for the option agreement. During the year ending December 31, 2014, we made additional option payments of $1.5 million. We will continue to make annual option payments throughout the term of the option agreement, which, during the initial option period could total up to $10 million. The option and exploration agreements provide for exploration rights and exclusive options to lease three separate coal deposits on the Crow Indian Reservation over an initial five-year term, with two extension periods through 2035 if certain conditions are met. Upon the exercise of an option or options to lease, we would pay the Crow Tribe an amount equal to $0.08 per ton to $0.15 per ton, depending on the lease area and coal deposit and subject to adjustment for inflation. The agreements also set forth adjustable royalty rates, ranging from 7.5% to 15% of the coal sales price FOB at the mine site and contain standard coal production taxes to be paid to the Crow Tribe. The coal located at the Crow project is similar quality to that of our Spring Creek Mine and offers lower sodium levels. We are undertaking the exploration program and evaluating the development options for this project and believe that its proximity to the Spring Creek Mine and the Youngs Creek project represents an opportunity to optimize our mine developments in the Northern PRB region.

The map below shows where the Youngs Creek project and Crow project are located relative to our Spring Creek Mine.

(1) Non-reserve coal deposits are not reserves under SEC Industry Guide 7. Estimates of non-reserve coal deposits are subject to further exploration and development, are more speculative, and may not be converted to future reserves of the company.

Table of Contents

Customers, Contracts and Logistics Services

We focus on building long-term relationships with customers through our reliable performance and commitment to customer service. We supply coal to 95 domestic and foreign electric utilities and over 72% of our sales were to customers with an investment grade credit rating as of December 31, 2014. Furthermore, over 85% of our 2014 sales were to customers with whom we have had relationships for more than 10 years. During 2014, approximately 47% of our consolidated revenue was derived from our top ten customers. No customer accounted for 10% or more of our total revenue in 2014. A significant portion of our revenue for the Logistics and Related Activities segment is derived from entities owned or controlled by Korea Electric Power Corporation. We believe we could make up the loss of any sales caused by the loss of one or more of these entities; however, we cannot guarantee that the prices we would receive from any replacement sales would be at a price as favorable as the original sales price.

Coal produced approximately 39% of electricity generation in the U.S. through November 2014. The following map shows the percentage of our tons sold by state of destination during 2014 from coal produced at the three mines we own and operate. Our coal supplies fueled approximately 4% of the electricity generated in the U.S. in 2014. We also supplied approximately 5% of the tons produced at our mines to customers outside of the U.S. in 2014.

We categorize our customers by how we sell coal to them. Our mine customers purchase coal directly from our mine sites, where the sale occurs at the mine site and where title and risk of loss pass to the customer at that point. Mine customers arrange for and bear the costs of transporting their coal from our mines to their plants or other specified discharge points. Our mine customers are typically domestic utility companies primarily located in the mid-west and south central U.S., although we also sell to other domestic utility companies, as well as to third-party brokers.

Our logistics customers purchase coal from us, along with our logistics services to deliver the coal to the customer at a terminal or the customer s plant or other delivery point remote from our mine site. Title and risk of loss pass to the customer at the remote delivery point. Our logistics services include the purchase of coal from third parties or from our owned and operated mines, at market prices, as well as the contracting and coordination of the transportation and other handling services from third-party operators, which are typically rail and terminal companies. Our rail and terminal contracts involve significant take-or-pay commitments. Logistics customers are primarily foreign and domestic utility companies as well as third-party brokers. With respect to our international sales, at present, we are primarily focused on end-user customers; however a small portion of our sales are made to international traders who sell on to end-user customers. In 2014, we were the largest U.S. exporter of thermal coal into South Korea.

Mine Customers

Long-term Coal Sales Agreements

As is customary in the coal industry, we generally enter into fixed price, fixed volume supply contracts with our mine customers. Contracts with our mine customers generally have terms of one to five years, although some are as short as

Table of Contents

one to six months and others may be longer than ten years. For the year ended December 31, 2014, approximately 79% of our total revenue attributable to our Owned and Operated Mines segment was derived from long-term supply contracts with terms of one year or greater and approximately 43% of our committed tons to mine customers was associated with contracts that had three years or more remaining on their term.

Our coal is primarily sold on a mine-specific basis to utility customers through a request-for-proposal process. The terms of our coal sales agreements result from competitive bidding and extensive 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, impact of future regulatory changes, extension options, force majeure, termination, assignment and other provisions.

Our coal supply contracts typically contain hardship provisions to adjust the base price due to new statutes, ordinances or regulations that affect our costs related to performance of the agreement. Additionally, some of our contracts contain provisions that allow for the recovery of costs incurred as a result of 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. In addition, a small number of our contracts contain clauses that may allow customers to terminate the contract in the event of significant changes in environmental laws and regulations, which result in the customer being unable to perform under the terms of the contract.

Most of our coal supply contracts to mine customers include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of these contracts that extend for a four- or five-year term or longer may include variable pricing. These price re-opener and index provisions may allow either 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 between a specified range of prices. In some agreements, if the parties do not agree on a new price, either party has an option to terminate the contract. Under some of our contracts, we have the right to match lower prices offered to our customers by other suppliers.

Quality and volumes for the coal are stipulated in coal supply contracts. Some customers are allowed to vary the amount of coal taken under the contract. Most of our coal supply contracts contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics, such as heat content, sulfur, ash and ash fusion temperature. Our contracts also typically attempt to account for the low sulfur content of our coal by reflecting a market adjustment for the low sulfur in the contract price or through an adjustment calculated based on the as-delivered average sulfur content of our coal, or both. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Contracts with our mine customers also typically contain force majeure provisions allowing temporary suspension of performance by us or our customers for the duration of specified 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. These contracts generally provide that, in the event a force majeure circumstance exceeds a certain time period (e.g., 60-90 days), the unaffected party may have the option to terminate the transaction or transactions under the agreement. Some of those contracts stipulate that this tonnage can be made up by mutual agreement or at the discretion of the buyer. Generally, contracts with our mine customers allow our customers to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a force majeure under the terms of the contract between the mine customer and the railroad.

Many of our contracts contain clauses that require us and our customers to maintain a certain level of creditworthiness or provide appropriate credit enhancement upon request. The failure to do so can result in a suspension of shipments under the contract. In some of our contracts, we have a right of substitution, 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 delivered cost.

Generally, under the terms 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, other than from their own negligence, and for damage to their equipment due to non-coal materials being included with our coal before leaving our property.

Table of Contents

Transportation

Transportation is typically one of the largest components of a purchaser s total cost. Coal used for domestic consumption by our mine customers is sold FOB at the mine or nearest loading facility, and the purchaser of the coal bears the transportation costs and risk of loss. Most electric generators arrange long-term shipping contracts with rail or barge companies to assure stable delivery costs. Our mines are served by the BNSF and/or UP railways.

Although the purchaser pays the freight, transportation costs still are important to coal mining companies because the purchaser will consider the delivered cost of coal, including transportation costs, in determining from which mines it will purchase. Transportation costs borne by the customer vary greatly based on each customer s proximity to the mine.

Logistics Customers

Long-term Coal Sales Agreements

We generally enter into binding contracts that are fixed-price, fixed-volume supply contracts with our logistics customers. Contracts with our logistics customers generally have terms of one to three years. The terms of our sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re-opener terms, logistics and coal quality requirements, quantity parameters, permitted sources of supply, impact of future regulatory changes, extension options, force majeure, termination, assignment and other provisions.

With many of our international logistics customers, we have contracts that contain evergreen clauses. A combination of annual, semi-annual, or quarterly pricing negotiations consistent with conventional industry standards for the Asian Pacific region result in fixed-price sales. Our Asian delivered sales are priced broadly in line with a number of relevant international coal indices adjusted for energy content and other quality and delivery criteria. These indices include the Newcastle benchmark price, which is an established index for high Btu Australian thermal coal available to be loaded on a vessel at a coal terminal near Newcastle, north of Sydney. Based on the comparative quality and transport costs, our delivered sales are generally priced at approximately 60% to 75% of the forward Newcastle price.

Contracts with our logistics customers include terms similar to those described for our mine customers and may also include terms relating to:

- demurrage fees for international contracts, charged to us when a vessel is not dispatched on time;

- fixed pricing for the first year of sales, and a provision providing for future years pricing to be negotiated at a specific point in time related to some of our foreign contracts; and

- additional coal quality requirements, such as grindability, which deals with the hardness of the coal, and ash fusion temperature, which measures the softening and melting behavior of the ash contained in the coal.

Transportation and Logistics Services

For our logistics customers, we provide a variety of services designed to facilitate the sale and delivery of coal. These services include the purchase of coal from third parties or from our owned and operated mines, coordination of the transportation and delivery of purchased coal, negotiation of take-or-pay rail agreements and take-or-pay terminal agreements and demurrage settlement with vessel operators. We also bear the costs of transporting the coal to the delivery point. For our international customers, this includes export terminals located in the Pacific Northwest, which can be over 2,600 miles from our mines and involve transporting over three different railroads. Our logistics customers located overseas are generally responsible for paying the cost of ocean freight, although occasionally we may arrange that transportation as well.

We have an agreement with an unaffiliated Korean representative company, WoonBong Energy, which helps us facilitate our sales in South Korea. WoonBong Energy provides market research on Korean coal markets, acts as an intermediary for communications with our Korean customers and assists with logistics issues in sales to Korean customers. WoonBong Energy provides these services exclusively for us in South Korea.

To help support and ensure export terminal capacity for our anticipated export sales, we enter into long-term throughput agreements with export terminal companies and railroads. These types of take-or-pay agreements require us to pay for a minimum quantity of coal to be transported on the railway or through the terminal regardless of whether we sell any coal. If we fail to make sufficient export sales to meet our minimum obligations under the take-or-pay agreements, we are

Table of Contents

still obligated to make payments to the export terminal company or railroad. In 2011, we entered into a long-term throughput contract with Westshore for a portion of our anticipated export sales through their export terminal in Vancouver, British Columbia. In August 2014, we increased our long-term committed capacity at Westshore from 2.8 million tons to 6.3 million tons initially and increasing to 7.2 million tons in 2019. In addition, the revised agreement extended the term of our throughput agreement by two years through the end of 2024. In early 2015, as current international prices remain low, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons, thereby reducing our committed 2015 capacity at Westshore to 5.8 million tons.

As part of the Decker Mine divestiture transaction, we were granted a throughput option for up to 7.7 million tons per year at the proposed Millennium Bulk Terminals coal export facility in Washington State. The proposed new coal export facility is currently in the permitting stage and is planned to be developed in two phases. Our option covers up to 3.3 million tons per year of capacity during the first phase of development and an additional 4.4 million tons per year once the second phase of development is reached. Our throughput capacity will have an initial term of 10 years, with four renewal options for five-year terms. Our option is exercisable following the successful completion of the ongoing permit process for the terminal, the timing and outcome of which are uncertain.

Also, in February 2013, we announced a throughput option agreement with SSA Marine that provides us with an option for up to 17.6 million tons of capacity per year through the planned dry bulk cargo Gateway Pacific Terminal at Cherry Point in the State of Washington. This agreement requires us to make annual option payments, aggregating up to a maximum of $16 million over a five-year period. The initial shipping term is 10 years with an option to enter into two five-year extension terms. Our potential share of capacity will depend upon the ultimate capacity of the terminal and is subject to the terms of the option agreement. The terminal would accommodate cape size vessels. Our option is exercisable following the successful completion of the ongoing permit process for the terminal, which is uncertain. We also continue to explore other Pacific Northwest terminal opportunities as part of our efforts to grow our export sales.

Also included in the costs within our Logistics and Related Activities segment are fees to cover rail and export terminal charges, as well as fees to cover capital costs and investments that we incur to enable us to provide logistics services to our logistics customers, such as the purchase or lease of rail cars.

Broker Sales and Third-Party Sources

From time to time, we purchase coal through brokers. We also sell any excess produced coal to brokers and third-party sources, including brokers who sell to end users in foreign countries. For delivery during the year ended December 31, 2014, we purchased and resold 0.1 million tons through brokers and third-party sources.

Sales and Marketing

We have a team of experienced sales, marketing and customer service personnel. To help develop and maintain the relationships we have with our mine and logistics customers, we have divided the department into teams consisting of:

- Sales and Marketing, which focuses on traditional requests for proposals by our mine customers;

- Customer Service, which provides contract and after-sales support to our customers;

- Logistics and Industrial Sales, which focuses on logistics, transportation and related services on behalf of our Logistics and Related Activities segment;

- Trading and Revenue Management, which provides industry insight, recommends pricing strategies and participates in the spot and forward markets; and

- Export Sales, which focuses on sales to our international logistics customers.

As of December 31, 2014, we had 21 employees in our sales and marketing department.

Suppliers

Principal supplies used in our business include heavy mobile equipment, 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 portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business such as dragline shovel parts and services and tires. We believe adequate substitute suppliers are available. For further discussion of our suppliers, see Item 1A Risk Factors Risks Related to Our Business and

Table of Contents

Industry Increases in the cost of raw materials and other industrial supplies, or the inability to obtain a sufficient quantity of those supplies, could increase our operating expenses, disrupt or delay our production and materially adversely affect our profitability.

Competition

The coal industry is highly competitive. See Item 1A Risk Factors Risks Related to Our Business and Industry Competition with domestic and foreign coal producers and with producers of natural gas and other competing energy sources may negatively affect our sales volumes and our ability to sell coal at a favorable price. We compete directly with all coal producers and indirectly with other energy producers throughout the U.S. and, for our export sales, internationally. The most important factors on which we compete with other coal producers are coal price, coal quality and characteristics, costs to transport the coal, customer service and the reliability of supply. Demand for coal and the prices that we will be able to obtain for our coal are closely linked to coal consumption patterns of the domestic and foreign electric generation industries. These coal consumption patterns are influenced by factors beyond our control, including the supply and demand for domestic and foreign electricity, domestic and foreign governmental regulations and taxes, environmental and other regulatory changes, technological developments, the price and availability of other fuels, such as natural gas and crude oil, the availability of subsidies, and renewable mandates designed to encourage greater use of alternative energy sources, including hydroelectric, nuclear, wind and solar power, and currency exchange rate fluctuations, all of which can decrease demand for thermal coal or may decrease demand for PRB coal compared to other global coal basins.

Because most of the coal in the vicinity of our mines is owned by the U.S. federal government, we compete with other coal producers operating in the PRB for additional coal through the LBA process. This process is competitive and we expect the competition for LBAs to remain strong.

Employees

As of December 31, 2014, we had approximately 1,600 full-time employees. None of our employees are currently parties to collective bargaining agreements. We believe that we have good relations with our employees. As of December 31, 2014, we had 215 external contractors on a full-time, equivalent basis.

Executive Officers

Set forth below is information concerning our current executive officers as of December 31, 2014.

Name	Age	Position(s)
Colin Marshall	50	President, Chief Executive Officer and Director
Michael Barrett	45	Executive Vice President and Chief Financial Officer
Gary Rivenes	44	Executive Vice President and Chief Operating Officer
Bryan Pechersky	44	Executive Vice President, General Counsel and Corporate Secretary
Bruce Jones	56	Senior Vice President, Technical Services
Cary Martin	62	Senior Vice President, Human Resources

Todd Myers	50	Senior Vice President, Business Development
James Orchard	54	Senior Vice President, Marketing and Government Affairs
Heath Hill	44	Vice President and Chief Accounting Officer

Colin Marshall has served as our President, Chief Executive Officer and a director since July 2008. Previously, he served as the President and Chief Executive Officer of RTEA from June 2006 until November 2009. From March 2004 to May 2006, Mr. Marshall served as General Manager of Rio Tinto s Pilbara Iron s west Pilbara iron ore operations in Tom Price, West Australia, from June 2001 to March 2004, he served as General Manager of RTEA s Cordero Rojo Mine in Wyoming, and from August 2000 to June 2001, he served as Operations Manager of RTEA s Cordero Rojo Mine. Mr. Marshall worked for Rio Tinto plc in London as an analyst in the Business Evaluation Department from 1992 to 1996. From 1996 to 2000, he was Finance Director of the Rio Tinto Pacific Coal business unit based in Brisbane Australia. Mr. Marshall holds a Bachelor of Engineering degree and a Master s degree in mechanical engineering from Brunel University and a Master of Business Administration from the London Business School.

Table of Contents

Michael Barrett has served as our Executive Vice President and Chief Financial Officer since September 2008. Previously, he served as Chief Financial Officer of RTEA from April 2007 until November 2009, and as Acting Chief Financial Officer of RTEA from January 2007 to March 2007. From November 2004 to April 2007, Mr. Barrett served as Director, Finance & Commercial Analysis of RTEA, and from December 2001 to November 2004, he served as Principal Business Analyst of Rio Tinto Iron Ore s new business development group. From May 1997 to May 2000, Mr. Barrett worked as a Senior Business Analyst for WMC Resources Ltd, a mining company, and was Chief Financial Officer and Finance Director of Medtech Ltd. and Auxcis Ltd., two technology companies listed on the Australian stock exchange, from May 2000 to December 2001. From August 1991 to May 1997, he held positions with PricewaterhouseCoopers in England and Australia. Mr. Barrett received his Bachelor s degree with joint honors in economics and accounting from Southampton University and is a chartered accountant. As previously announced, Mr. Barrett will resign from his position as our Executive Vice President and Chief Financial Officer effective March 16, 2015.

Gary Rivenes has served as our Executive Vice President and Chief Operating Officer since October 2009. Previously, he served as Vice President, Operations, of RTEA from December 2008 until November 2009, and as Acting Vice President, Operations, of RTEA from January 2008 to November 2008. From September 2007 to December 2007, Mr. Rivenes served as General Manager for RTEA s Jacobs Ranch Mine, from October 2006 to September 2007, he served as General Manager for RTEA s Antelope Mine and from November 2003 to September 2006, he served as Manager, Mine Operations for RTEA s Antelope Mine. Prior to that, he worked for RTEA in a variety of operational and technical positions for RTEA s Antelope, Colowyo and Jacobs Ranch mines since 1992. Mr. Rivenes holds a Bachelor of Science in mining engineering from Montana College of Mineral, Science & Technology.

Bryan Pechersky has served as our Executive Vice President since January 2015, our General Counsel since January 2010, and our Corporate Secretary since March 2013. Prior to his promotion to Executive Vice President, he served as Senior Vice President beginning in 2010. Previously, Mr. Pechersky was Senior Vice President, General Counsel and Secretary for Harte-Hanks, Inc., a worldwide, direct and targeted marketing company from March 2007 to January 2010. Prior to that, he also served as Senior Vice President, Secretary and Senior Corporate Counsel for Blockbuster Inc., a global movie and game entertainment retailer from October 2005 to March 2007, and was Deputy General Counsel and Secretary for Unocal Corporation, an international energy company acquired by Chevron Corporation in 2005, from March 2004 until October 2005. While in these capacities, Mr. Pechersky s responsibilities included advising on various legal, regulatory and compliance matters, transactions and other responsibilities that are common for a general counsel and corporate secretary. Mr. Pechersky was in private practice for approximately seven years with the international law firm Vinson & Elkins L.L.P. before joining Unocal Corporation. Mr. Pechersky also served as a Law Clerk to the Hon. Loretta A. Preska, Chief Judge of the U.S. District Court for the Southern District of New York in 1995 and 1996. Mr. Pechersky earned his Bachelor s degree and Juris Doctorate from the University of Texas, Austin, Texas.

Bruce Jones has served as our Senior Vice President, Technical Services since July 2013, with responsibilities in strategic and long-term mine planning, geological services, land management and environmental affairs. Prior to his appointment as Senior Vice President, Mr. Jones was General Manager of our Spring Creek Mine from March 2007 to July 2013. Before joining the Spring Creek Mine, Mr. Jones was the Operations Manager for Kennecott Utah Copper at the Bingham Canyon Mine in Bingham Canyon, Utah. Mr. Jones began his career as a mining engineer for Inspiration Coal, Inc. in 1982 and has worked in several sectors of the mining industry. During his career, Mr. Jones has held engineering and operations management positions at gold, copper, and coal mining operations. Mr. Jones holds a Bachelor of Science degree in mining engineering from the University of Wisconsin-Platteville and a Master of Business Administration from the University of Utah. Mr. Jones is a registered professional engineer in Kentucky and Utah.

Cary Martin has served as our Senior Vice President, Human Resources since October 2009. Previously, he served as Vice President / Corporate Officer of Human Resources for OGE Energy Corp., an electric utility and natural gas processing holding company from September 2006 until March 2008, and as a Segment Vice President for several different divisions of SPX Corporation, an international multi-industry manufacturing and services company from December 1999 until May 2006. In these capacities, Mr. Martin s responsibilities included oversight of employee and labor relations, workforce planning, employee development, compensation administration, policies and procedures and other responsibilities that are common for a human resources executive. From 1982 until 1999, Mr. Martin served in various management and officer positions for industries ranging from medical facilities to cable manufacturers. Mr. Martin received his Bachelor s degree in business administration from the

University of Missouri and his Master s degree in management sciences from St. Louis University.

Todd Myers has served as our Senior Vice President, Business Development since July 2010. Previously, he served as President of Westmoreland Coal Sales Company. Prior to that, Mr. Myers served in other senior leadership positions with Westmoreland Coal in marketing and business development during two periods dating to 1989. In his various capacities with

Table of Contents

Westmoreland Coal, Mr. Myers s responsibilities included developing and implementing corporate merger and acquisition strategies, divesting coal related assets, negotiating complex transactions and other responsibilities generally attributable to the management of coal businesses. Mr. Myers also spent five years with RDI Consulting, a leading consulting firm in the energy industry, where he led the energy and environment consulting practice. In 1987, Mr. Myers served as a staff assistant in the U.S. House of Representatives. Mr. Myers earned his Bachelor of Arts in political science from Pennsylvania State University in University Park, Pennsylvania, and a Master of International Management from the Thunderbird Graduate School of Global Management in Glendale, Arizona.

James Orchard has served as our Senior Vice President, Marketing and Government Affairs since October 2009. Previously, he served as Vice President, Marketing and Sustainable Development for RTEA from March 2008 until November 2009. From January 2005 to March 2008, Mr. Orchard was Director of Customer Service for RTEA. Prior to that he worked for Rio Tinto s Aluminum division in Australia and New Zealand for over 17 years, where he held a number of technical, operating, process improvement and marketing positions, including as manager of Metal Products from January 2001 to January 2005. Mr. Orchard graduated from the University of New South Wales with a Bachelor of Science and a PhD in industrial chemistry.

Heath Hill has served as our Vice President and Chief Accounting Officer since September 2010. Previously, Mr. Hill served in various capacities with PricewaterhouseCoopers LLP, our independent public accountants, from September 1998 to September 2010, including Senior Manager from September 2006 to September 2010, and Manager from September 2003 to September 2006. While with PricewaterhouseCoopers LLP, Mr. Hill s responsibilities included assurance services primarily related to SEC registrants, including annual audits of financial statements and internal controls, public debt offerings and IPO transactions. From June 2003 to June 2005 he held a position with PricewaterhouseCoopers in Germany serving U.S. registrants throughout Europe. Mr. Hill never worked on any engagements or projects for CPE Inc. or its predecessor, Rio Tinto, while he was with PricewaterhouseCoopers LLP. Mr. Hill earned his Bachelor s degree in accounting from the University of Northern Colorado and is an active certified public accountant. As previously announced, Mr. Hill will replace Mr. Barrett as our Executive Vice President and Chief Financial Officer upon Mr. Barrett s resignation effective March 16, 2015.

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to various matters, including air quality standards, water pollution, plant and wildlife protection, the discharge of materials into the environment and the effects of mining on surface and groundwater quality and availability. These laws and regulations, which are extensive, change frequently, and have tended to become stricter over time, have had, and will continue to have, a significant adverse effect on our production costs and our competitive position relative to certain other sources of electricity generation. Future laws, regulations or orders, including those relating to global climate change, may 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. See Environmental and Other Regulatory Matters Global Climate Change.

We are committed to conducting our mining operations in compliance with all applicable federal, state and local laws and regulations. We have procedures in place that are designed to enable us to comply with these laws and regulations. As an example, all of the mines we operate are certified to the international standard for environmental management systems (ISO 14001). We believe we are substantially in compliance with applicable laws and regulations. However, due to the complexity and interpretation of these laws and regulations, we cannot guarantee that we have been or will be at all times in complete compliance.

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 data to federal, state or local authorities 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 EIS must be prepared to assist the BLM in determining the potential environmental impact of lease issuance, including any direct and indirect effects from the mining, transportation and burning of coal. In recent years, particular attention has been focused on the impact of the production and usage of coal on global climate change. This has resulted in extensive comments and regulatory litigation from environmental groups, including, for example, unsuccessful challenges related to the EIS prepared in connection with the West Antelope II LBA. Accordingly, our nominations or lease applications may be subject to delays or challenges. In order to obtain mining permits and approvals from federal and state regulatory authorities, mine operators must also submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, we submit the

Table of Contents

necessary permit applications several months or even years before we plan to begin mining a new area. 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, stockholders 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 by these interested persons and entities could provide a basis to revoke our existing permits and to deny the issuance of additional permits. As a result of these requirements, the authorization, permitting and implementation requirements imposed by federal, state and local authorities may be costly and time consuming and may limit or delay commencement or continuation of mining operations. Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under governing laws, rules, and regulations. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Permitting requirements also require, under certain circumstances, that we obtain surface owner consent if the surface estate has been split from the mineral estate. This requires us to negotiate with third parties for surface access that overlies coal we acquired or intend to acquire. These negotiations can be costly and time-consuming, lasting years in some instances, which can create additional delays in the permitting process. If we cannot successfully negotiate for land access, we could be denied a permit to mine coal we already own.

Surface Mining Control and Reclamation Act

SMCRA establishes mining, environmental protection, reclamation and closure standards for all aspects of surface coal mining. Mining operators must obtain SMCRA permits and permit renewals from the federal Office of Surface Mining (OSM) or from the applicable state agency if the state agency has obtained regulatory primacy by developing a mining regulatory program no less stringent than that established under SMCRA. Both Wyoming and Montana, where our owned and operated mines are located, have achieved primacy to administer the SMCRA program.

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, surface runoff and drainage control, establishment of suitable post mining land uses and re-vegetation. 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 typically includes surveys and/or assessments of: 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 surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application, which address the provisions and performance standards of the state s equivalent SMCRA regulatory program. SMCRA permit applications also include information used for documenting surface and mineral ownership, variance requests, access roads, 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 regulations, including information regarding mining and compliance history. A mine operator must also submit a bond or otherwise secure the performance of all reclamation obligations associated with the proposed activities.

Upon submission to the regulatory agency, a permit application goes through an administrative completeness review and a thorough technical review. Public notice of the proposed permit is required, beginning a notice and comment period that is required before a permit can be issued. It is not uncommon for a SMCRA mine permit application to take over two years to prepare and review, depending on the size and complexity of the mine, and another two or more years for the permit to be issued, depending primarily on the regulatory authority s approach to handling comments and objections 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 described above, the Abandoned Mine Land Fund, which was created by SMCRA, imposes 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. In 2014, we recorded $24.6 million of expense related to these reclamation fees.

Table of Contents

Surety Bonds

Federal and state laws require a mine operator to secure the performance of its reclamation and lease obligations required under SMCRA through the use of surety bonds or other approved forms of security to cover the costs the state would incur if the mine operator were unable to fulfill its obligations. As of December 31, 2014, there were approximately $448.9 million in third-party surety bonds outstanding to primarily secure the performance of our reclamation and lease obligations (including approximately $0.6 million for the Youngs Creek project), and we were self-bonded for $200 million. At some point, federal and state laws may be amended to require certain forms of financial assurance that are more costly to obtain, such as letters of credit.

Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 (the Mine Act), significantly expanded the enforcement of safety and health standards and imposed 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 state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is among the most comprehensive and pervasive systems for protection of employee health and safety affecting any segment of U.S. industry. The Mine Act is a strict liability statute that requires mandatory inspections of surface and underground coal mines and requires the issuance of enforcement action when it is believed that a standard has been violated. A penalty is required to be imposed for each cited violation. Negligence and gravity assessments result in a cumulative enforcement arrangement that may result in the issuance of withdrawal orders. The Mine Act also contains criminal liability provisions. For example, it imposes criminal liability for corporate operators who knowingly or willfully authorize, order or carry out violations and for any person who knowingly falsifies records required under the Mine Act. The Mine Act also provides that civil and criminal penalties may be assessed against individual agents, officers and directors who knowingly authorize, order or carry out violations.

In 2006, in response to underground mine accidents, Congress enacted the Mine Improvement and New Emergency Response Act (the MINER Act). The MINER Act significantly amended the Mine Act, requiring improvements in mine safety practices, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection and enforcement activities. Since passage of the MINER Act, and particularly since the April 2010 explosion at Massey Energy Company s (now Alpha Natural Resources) Upper Big Branch Mine, enforcement scrutiny has increased, including more inspection hours at mine sites, increased numbers of inspections and increased issuance of the number and the severity of enforcement actions and related penalties. Various states also have enacted their own new laws and regulations addressing many of these same subjects. MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards. Our compliance with these or any new mine health and safety regulations could increase our mining costs.

We have implemented various internal standards to promote employee health and safety. In addition, we are also Occupational Health and Safety Assessment Series 18001 certified. According to MSHA data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must pay federal black lung benefits to claimants who are current and former employees and also make payments to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to January 1, 1970. The trust fund is funded by an excise tax on production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price. The excise tax does not apply to coal shipped outside the U.S. In 2014, we recorded $42.0 million of expense related to this excise tax.

The Patient Protection and Affordable Care Act includes significant changes to the federal black lung program including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes could have a material impact on our costs expended in association with the federal black lung program. For miners last employed as miners after 1969 and who are determined to have contracted black lung, we maintain coverage sufficient to cover the cost of present and future claims through the use of

Table of Contents

trusts or insurance policies. We may also be liable under state laws for black lung claims that are covered through insurance policies.

Clean Air Act

The federal Clean Air Act (CAA) and comparable state laws that regulate air emissions affect coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations include CAA permitting requirements and emission control requirements relating to air pollutants, including particulate matter, which may include controlling fugitive dust. The CAA indirectly affects coal mining operations by extensively regulating the emissions of particulate matter, sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fired power plants. In recent years, Congress has considered legislation that would require increased reductions in emissions of sulfur dioxide, nitrogen oxide and mercury. In addition to the GHG issues discussed below, the air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the following:

- *Acid Rain.* Title IV of the CAA requires reductions of sulfur dioxide emissions by electric utilities. Affected power plants have sought to reduce sulfur dioxide emissions by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing or trading sulfur dioxide emission allowances. We cannot accurately predict the future effect of these Clean Air Act provisions on our operations. These acid rain requirements would not be supplanted by CSAPR, which is scheduled to require implementation beginning in 2015.

- *NAAQS for Criterion Pollutants.* The CAA requires the EPA to set standards, referred to as NAAQS, for six common air pollutants, including nitrogen oxide, sulfur dioxide, particulate matter, and ozone. Areas that are not in compliance (referred to as non-attainment areas) with these standards must take steps to reduce emissions levels. Although our operations are not currently located in non-attainment areas, we could be required to incur significant costs to install additional emissions control equipment, or otherwise change our operations and future development if that were to change. Over the past several years, the EPA has revised its NAAQS for nitrogen oxide, sulfur dioxide, and particulate matter, and, in November 2014, proposed a revised standard for ozone, in each case making the standards more stringent. Additionally, the EPA has made finalized initial non-attainment designations for its revised nitrogen oxide, sulfur dioxide, and particulate matter, although the EPA has deferred making attainment designations related to certain geographic areas in various instances where additional data and/or monitoring for particular NAAQS pollutants is necessary to determine whether such areas are in attainment. Pursuant to these efforts, or upon the finalization of the EPA s proposed revisions to the ozone NAAQS, which is currently expected by October 2015, certain areas of the country currently in compliance with the various NAAQS standards may be reclassified as non-attainment. Such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. We do not know whether or to what extent these developments might affect our operations or our customers businesses.

- *Clean Air Interstate Rule and Cross-State Air Pollution Rule.* CAIR calls for power plants in 28 states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system now in effect for acid rain. In June 2011, the EPA finalized CSAPR, a replacement rule to CAIR, which requires 28 states in the Midwest and eastern seaboard of the U.S.to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Nitrogen oxide and sulfur dioxide emissions reductions were scheduled to commence in 2012, with further reductions effective in 2014. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) vacated CSAPR and ordered the EPA to continue enforcing CAIR. In April 2014, the U.S. Supreme Court reversed the D.C. Circuit s decision vacating CSAPR. The EPA subsequently moved the Appeals Court for an order lifting the stay of CSAPR and extending the CSAPR compliance deadlines. In October 2014, the Court granted the EPA s request to lift the stay, and in November 2014, the EPA issued an interim final rule reconciling the CSAPR rule with the Court s order, which calls for Phase 1 implementation in 2015 and Phase 2 implementation in 2017. For states to meet their requirements under CSAPR, a number of coal-fired electric generating units will likely need to be retired, rather than retrofitted with the necessary emission control technologies, reducing demand for thermal coal.

- *NO_x SIP Call.* The NO_x SIP Call program was established by the EPA in October 1998 to reduce the transport of nitrogen oxide and ozone on prevailing winds from the Midwest and South to states in the Northeast, which alleged that they could not meet federal air quality standards because of migrating pollution. The program is designed to reduce nitrogen oxide emissions by one million tons per year in 22 eastern states and the District of Columbia. As a result of the program, many power plants have been or will be required to install additional emission control measures, such as selective catalytic reduction devices. Installation of additional emission control measures will make it more costly to operate coal-fired power plants, potentially making coal a less attractive fuel.

- *Mercury and Hazardous Air Pollutants.* In February 2012, the EPA formally adopted a rule to regulate emissions of mercury and other metals, fine particulates and acid gases such as hydrogen chloride from coal- and oil-fired power plants, referred to as MATS. In March 2013, the EPA finalized reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits for new coal-fired units to levels considered attainable by existing control technologies. In subsequent litigation, the D.C. Circuit upheld various portions of the rulemaking in two separate decisions issued in March and April 2014, respectively. In November 2014, the U.S. Supreme Court granted certiorari to review the D.C. Circuit decisions. The litigation does not include provisions for a stay and the timeline for general compliance with the standards remains at April 2015. Some utilities have been moving forward with installation of equipment necessary to comply with MATS, and the EPA and states have been granting additional time beyond the 2015 deadline (but no more than one extra year) for facilities that need more time to upgrade and complete those installations. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by the EPA, states, Congress or pursuant to an international treaty may decrease the future demand for coal, but we are currently unable to predict the magnitude of any such effect. Like CSAPR, MATS and other similar future regulations could accelerate the retirement of a significant number of coal-fired power plants. We continue to evaluate the possible scenarios associated with these regulatory programs and the effects they may have on our business and our results of operations, financial condition or cash flows.

- *Regional Haze, New Source Review and Methane.* The EPA has initiated a regional haze program to protect and improve visibility at and around national parks, national wilderness areas and international parks. In December 2011, the EPA issued a final rule under which the emission caps imposed under CSAPR for a given state would supplant the obligations of that state with regard to visibility protection. In May 2012, the EPA finalized a rule that allows the trading programs in CSAPR to serve as an alternative to determining source-by-source Best Available Retrofit Technology (BART). This rule provides that states in the CSAPR region can substitute participation in CSAPR for source-specific BART for sulfur dioxide and/or nitrogen oxides emissions from power plants. The Tenth Circuit Court of Appeals is hearing Wyoming s challenge to the EPA s partial disapproval of the State s related plan for reducing emissions of haze-causing nitrogen dioxide. Wyoming s current plan to mitigate nitrogen dioxide will continue during the appeal. A final decision in the case likely will not come until late 2015 or early 2016, though, in September 2014, the Court stayed the EPA s rejection of Wyoming s plan. In addition, the EPA s new source review program under certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly change emissions, to install the more stringent air emissions control equipment required of new plants. Litigation seeking to force the EPA to list coal mines as a category of air pollution sources that endanger public health or welfare under Section 111 of the CAA and establish standards to reduce emissions from sources of methane and other emissions related to coal mines was dismissed by the D.C. Circuit in May 2014. In that case, the Court denied a rulemaking petition citing agency discretion and budgetary restrictions, and ruled the EPA has reasonable discretion to carry out its delegated responsibilities, which includes determining the timing and relative priority of its regulatory agenda. In July 2014, the D.C. Circuit denied a petition seeking a rehearing of the case en banc. Litigation around these issues may continue, and could result in the need for additional air pollution controls for coal fired units and our operations.

Global Climate Change

There are three important sources of GHGs associated with the coal industry. The end use of our coal in electricity generation is a source of GHGs. Combustion of fuel for mining equipment used in coal production is another source of GHGs. In addition, coal mining can release methane, a GHG, directly into the atmosphere. These emissions from coal consumption and production are potentially subject to regulation as part of regulatory initiatives to address global climate change and global warming. These regulatory initiatives may increase our costs and significantly decrease demand and prices for our coal.

The Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change (the Kyoto Protocol) became effective in 2005, and bound those developed countries that ratified it (which the U.S. did not do) to reduce their global GHG emissions. Discussions to develop a treaty to replace the Kyoto Protocol after its expiration in 2012 are still ongoing. Any future global agreement on climate change could further reduce demand and prices for our coal.

Table of Contents

The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including coal-fired electric power plants, and begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. These rules were legally challenged, but in June 2012, the D.C. Circuit denied these challenges. Among the rules promulgated after the EPA s endangerment finding was the Tailoring Rule, which requires that all new or modified stationary sources of GHGs that will emit more than 75,000 tons of carbon dioxide per year and are otherwise subject to CAA regulation, and any other facilities that will emit more than 100,000 tons of carbon dioxide per year, to undergo prevention of significant deterioration (PSD) permitting, which requires that the permitted entity adopt the best available control technology. As a result, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for and so discourage development of coal-fired power plants. In April 2012, the EPA published draft New Source Performance Standards for greenhouse gas emissions from new electric generating units. The EPA has stated that it intends to finalize the rule in mid-summer 2015. In its proposal, the EPA has concluded that partial carbon capture and sequestration is the appropriate emission standard for these sources. In June 2014, the EPA released the Clean Power Plan. The plan sets a national carbon pollution standard that will cut emissions produced by U.S. power plants by 2030, by 30% from 2005 levels. The Clean Power Plan does not require GHG emission cuts from specific power plants. Although states can choose to rely on the four measures set by the EPA to meet this goal, the states themselves will ultimately decide the means to use. States can develop individual plans, or they can collaborate with other states. These measures states may employ include: renewable energy standards, efficiency improvements at plants, switching to natural gas, transmission efficiency improvements, energy storage technology, and expanding renewables or nuclear, and energy conservation programs. Under the proposed rule, states will have until June 2016 to submit final plans, although extensions may be allotted if needed. The final rule is expected to be issued in mid-summer 2015 and the emission reductions are scheduled to commence in 2020. Nine states have already filed a legal challenge to the proposed rulemaking. Other legal challenges to rules issued by the EPA relating to GHG regulation are likely. While we believe that we are similarly situated with other producers of coal relative to any final rules that may be adopted by the EPA, we are not currently in a position to make any meaningful determination about the extent of the impacts to our operations.

Additionally, the U.S. Supreme Court, in a decision issued in June 2014, addressed whether the EPA s regulation of GHG emissions from new motor vehicles properly triggered GHG permitting requirements for stationary sources under the CAA. The decision reversed, in part, and affirmed, in part, a 2012 D.C. Circuit decision that upheld the EPA s GHG-related regulations. Specifically, the Court held that the EPA exceeded its statutory authority when it interpreted the CAA to require PSD and Title V permitting for stationary sources based on their potential GHG emissions. However, the Court also held that the EPA s determination that a source already subject to the PSD program due to its emission of conventional pollutants may be required to limit its GHG emissions by employing the best available control technology was permissible.

Various states and regions have adopted GHG initiatives and certain governmental bodies, including the State of California, have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities. A number of states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power.

These and other current or future global climate change laws, regulations, court orders or other legally enforceable mechanisms may in the future require additional controls on coal-fired power plants and industrial boilers and may cause some users of coal to switch from coal to alternative sources of fuel.

Clean Water Act

The Clean Water Act (CWA) and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including dredged or fill materials, into waters of the U.S. The CWA provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Legislation that seeks to clarify the scope of CWA jurisdiction is under consideration by Congress. Recent court decisions, regulatory actions and proposed legislation have created uncertainty over CWA jurisdiction and permitting requirements that could either increase or decrease the cost and time spent on CWA compliance.

CWA requirements that may directly or indirectly affect our operations include the following:

• *Wastewater Discharge.* Section 402 of the CWA 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 (NPDES), and corresponding programs implemented by state regulatory agencies. Regular monitoring, reporting and compliance with performance standards are preconditions for the issuance and renewal of

Table of Contents

NPDES permits that govern discharges into waters of the U.S. Failure to comply with the CWA or NPDES permits can lead to the imposition of significant penalties, litigation, compliance costs and delays in coal production. Furthermore, the imposition of future restrictions on the discharge of certain pollutants into waters of the U.S. could increase the difficulty of obtaining and complying with NPDES permits, which could impose additional time and cost burdens on our operations. For instance, waters that states have designated as impaired (i.e., as not meeting present water quality standards) are subject to Total Maximum Daily Load regulations, which may lead to the adoption of more stringent discharge standards for our coal mines and could require more costly treatment.

Likewise, when water quality in a receiving stream is better than required, states are required to conduct an anti-degradation review before approving discharge permits. Anti-degradation policies may increase the cost, time and difficulty associated with obtaining and complying with NPDES permits and may also require more costly treatment.

- *Dredge and Fill Permits.* Many mining activities, including the development of settling ponds and other impoundments, require a Section 404 permit from the Army Corps of Engineers (the Corps). Generally speaking, these Section 404 permits allow the placement of fill materials into navigable waters of the U.S. including wetlands, streams, and other regulated areas. The Corps has issued 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 (NWP 21) generally authorize the disposal of dredged or fill material from surface coal mining activities into waters of the U.S., subject to certain restrictions. NWP 21s are typically reissued for a five-year period and require appropriate mitigation, and permit holders must receive explicit authorization from the Corps before proceeding with proposed mining activities. The Corps reauthorized use of NWP 21 for surface coal mines in February 2012. The new NWP 21 imposes new limits on stream impacts and prohibits valley fills as well as limits applicability of NWP 21 to very small wetland areas. Expansion of our mining operations into new areas may trigger the need for individual Corps approvals which could be more costly and take more time to obtain.

Because of the U.S. Supreme Court s divided decision in Rapanos v. United States, there is some regulatory uncertainty about what constitutes jurisdictional waters and wetlands. Consequently, in April 2014, the EPA and the Corps released a proposed rule to revise the definition of waters of the United States (WOTUS) for all CWA programs. The proposed WOTUS rule could significantly expand federal control of land and water resources across the U.S., triggering substantial additional permitting and regulatory requirements. In March 2010, the Corps made a determination that there are no jurisdictional wetlands at our Spring Creek Mine. Similarly, in September 2012, the Corps made a determination of an absence of waters of the U.S. for our Antelope Mine. Therefore, the Corps authorization of mining activities is not required for currently permitted lands. In September 2014, the Corps authorized proposed operations under NWP 21 for our Cordero Rojo Mine. All jurisdictional determinations are resolved, where applicable. Where there are jurisdictional wetlands, our Wyoming coal mines continue to operate under their respective NWP 21 permits.

- *Cooling Water Intake*. In May 2014, the EPA issued a new final rule pursuant to Section 316(b) of the CWA that affects the cooling water intake structures at power plants in order to reduce fish impingement and entrainment. The rule is expected to affect over 500 power plants. These requirements could increase our customers costs and may affect the demand for coal, which may materially impact our results or operations.

Resource Conservation and Recovery Act

The EPA determined that coal combustion residues (CCR) do not warrant regulation as hazardous wastes under the Resource Conservation and Recovery Act (RCRA) in May 2000. Most state hazardous waste laws do not regulate CCR as hazardous wastes. The EPA also concluded that beneficial uses of CCR, other than for mine filling, pose no significant risk and no additional national regulations of such beneficial uses are needed. However, the EPA determined that national non-hazardous waste regulations under RCRA are warranted for certain wastes generated from coal combustion, such as coal ash, when the wastes are disposed of in surface impoundments or landfills or used as minefill. In December 2014, the EPA finalized regulations that address the management of coal ash as a non-hazardous solid waste under Subtitle D. The rules impose engineering, structural and siting standards on surface impoundments and landfills that hold coal combustion wastes and mandate regular inspections. The rule also requires fugitive dust controls and imposes various monitoring, cleanup, and closure requirements. There have also been several legislative proposals that would require the EPA to further regulate the storage of CCR. These requirements, as well as any future changes in the management of CCR, could increase our customers operating costs and potentially reduce their ability or need to purchase coal. In addition, contamination caused by

Table of Contents

the past disposal of CCR, including coal ash, can lead to material liability for our customers under RCRA or other federal or state laws and potentially reduce the demand for coal.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances into the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on hazardous substance generators, site owners, transporters, lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA currently excludes most wastes generated by coal mining and processing operations from the primary 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 CERCLA or similar state laws. Thus, we may be subject to liability under CERCLA and similar state laws for coal mines that we currently own, lease or operate or that we or our predecessors have previously owned, leased or operated, and sites to which we or our predecessors sent hazardous substances. We may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination and natural resource damages at sites where we control surface rights.

Endangered Species Act

The federal Endangered Species Act (the ESA) and counterpart state legislation protect species threatened with possible extinction. The U.S. Fish and Wildlife Service (the USFWS) works closely with the OSM and state regulatory agencies to ensure that species subject to the ESA are protected from mining-related impacts. A number of species indigenous to the areas in which we operate are protected under the ESA. Other species in the vicinity of our operations, such as the mountain plover, which the USFWS determined not to list as threatened in May 2011, may have their listing status reviewed in the future. Additionally, the USFWS is under the directives of an agreement to determine by September 2015 whether greater sage-grouse will be listed as a threatened species. That agreement is the subject of a legal challenge, and, in an effort to delay any potential action on the greater sage-grouse by the September 2015 deadline, Congress has passed a spending bill preventing USFWS from spending money in 2015 on rules that would protect the greater sage-grouse. In the meantime, several western states, including Montana and Wyoming, have taken actions to promote sage-grouse conservation to attempt to preclude a listing of the species by the USFWS. In the latter part of 2011, the BLM released an Instruction Memorandum on greater sage-grouse and formal planning processes for conservation measures for the species. In Wyoming, the BLM is reportedly engaged in revising its Resource Management Plan (RMP) to include additional sage-grouse protective measures. As of the end of 2014, the RMP has not been finalized. These and any similar future actions could result in more stringent requirements being issued by the BLM and other agencies involved in the leasing and permitting process. Should more stringent protective measures be applied or if the greater sage-grouse is listed as a threatened species by the USFWS, this could significantly impair our ability to conduct our mining operations or result in increased operating costs, heightened difficulty in obtaining future mining permits, or the need to implement additional mitigation measures.

Compliance with ESA requirements could have the effect of prohibiting or delaying us from obtaining mining permits. These requirements may also include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species or their habitats. For example, our Spring Creek coal mine applied for lease modification under the BLM leasing regulations, and the area we were proposing to include was declared core greater sage-grouse habitat by the Montana Fish, Wildlife and Parks Department. This requires mitigation of the impacts on the habitat in order for us to obtain approval of this lease modification. We may not be successful in obtaining this lease modification.

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 regulatory requirements. 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) are required to complete a screening review. Our mines are low risk, Tier 4 facilities which are not subject to additional security plans. In 2008, the Department of Homeland Security proposed regulation of ammonium nitrate under the ammonium nitrate security rule. Many of the requirements of the rule would be duplicative of those in place under the Bureau of Alcohol Tobacco and Firearms, including registration and background checks. Additional requirements may include tracking and verifications for each transaction related to ammonium nitrate. A final rule has yet to be issued. In

Table of Contents

December 2014, the OSM announced its decision to pursue a rulemaking to revise regulations under SMCRA which will address all blast generated fumes and toxic gases. The outcome of this rulemaking could materially adversely impact our cost or ability to conduct our mining operations.

National Environmental Policy Act

The National Environmental Policy Act (NEPA) requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment, such as issuing a permit or other approval. In the course of such evaluations, an agency will typically prepare an environmental assessment to assess the potential direct, indirect and cumulative impacts of a proposed project. Where the activities in question have significant impacts to the environment, the agency must prepare an EIS. Compliance with NEPA can be time-consuming and may result in the imposition of mitigation measures that could affect the amount of coal that we are able to produce from mines on federal lands, and may require public comment. Whether agencies have complied with NEPA is subject to protest, appeal or litigation, which can delay or halt projects. The NEPA review process, including potential disputes regarding the level of evaluation required for climate change impacts, may extend the time and/or increase the costs and difficulty for obtaining necessary governmental approvals, and may lead to litigation regarding the adequacy of the NEPA analysis, which could delay or potentially preclude the issuance of approvals or grant of leases.

Other Environmental Laws

We are required to comply with numerous other federal, state and local environmental laws and regulations in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, and the Toxic Substance Control Act and transportation laws adopted to ensure the appropriate transportation of our coal both nationally and internationally. Laws, regulations, and treaties of other countries may also adversely impact our export sales by reducing demand for PRB coal, or coal in general, as a source of power generation in those countries.

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 (SEC). You may access and read our filings without charge through the SEC s website at www.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, www.cloudpeakenergy.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 (720) 566-2900 or by mail at Cloud Peak Energy Inc., 385 Interlocken Crescent, Suite 400, Broomfield, Colorado, 80021, Attention: Vice President, Investor Relations. In addition to reports we file or furnish with the SEC, we publicly disclose material information from time to time in our press releases, at annual meetings of stockholders, in publicly accessible conferences and investor presentations, and through our website. The information on our website is not part of this Form 10-K.

Item 1A. ***Risk Factors.***

You should carefully consider the risk factors described below and other information contained in this Form 10-K. If any of the following risk factors, as well as other risks and uncertainties that are not currently known to us or that we currently believe are not material, actually occur, our business, financial condition and results of operations could be materially adversely affected and you may lose all or a significant part of your investment.

Risks Related to Our Business and Industry

A substantial or extended decline in the prices we receive for our coal and logistics services could reduce our revenue and profitability, result in losses, and decrease the value of our coal reserves.

Our revenue, results of operations, and the value of our coal reserves depend on the prices we receive for our coal and logistics services. Prices for coal tend to be cyclical, and over the last several years have become more volatile and depressed due to an oversupply of coal in the marketplace. The prices we receive for our coal and logistics services depend upon factors beyond our control, including:

- domestic and foreign supply and demand for coal, including Asian and other foreign demand for PRB coal exports, and the impact of domestic and foreign government energy and tax policies and currency exchange rate fluctuations;

Table of Contents

- domestic and foreign demand for electricity and steel;
- domestic and foreign economic conditions;
- the quantity, quality and price of coal available from domestic and foreign competitors or the resale market;
- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels, such as natural gas and crude oil, and alternative energy sources, such as nuclear, hydroelectric, wind and solar power, and the effects of technological developments related to these non-coal and alternative energy sources;
- adverse weather, climatic or other natural conditions, including natural disasters;
- legislative, regulatory and judicial developments, environmental regulatory changes, or changes in energy and tax policy and energy conservation measures that would adversely affect the coal or utility industries, such as legislation or regulation that limits carbon dioxide or sulfur dioxide emissions or provides for increased funding, subsidies or other incentives for, or mandates the use of, alternative energy sources;
- domestic and foreign governmental regulations and taxes, including with respect to air emission standards for coal-fired power plants, and the ability of coal-fired power plants to meet these standards by installing scrubbers or other means;
- changes in coal-fired power plant capacity and utilization, including the extent to which new coal plants are built in the United States and other countries;
- market price fluctuations for sulfur dioxide emission allowances;
- the capacity of, cost of, and proximity to, rail transportation and terminal facilities and rail and terminal performance; and
- the other risks described in this Item 1A.

A substantial or extended decline in the prices we receive for our coal and logistics services due to these or other factors could reduce our revenue and profitability, cash flows, liquidity, and value of our coal reserves and result in losses.

Competition with domestic and foreign coal producers and with producers of natural gas and other competing energy sources may negatively affect our sales volumes and our ability to sell coal at a favorable price.

The coal industry is highly competitive. We compete directly with all domestic and many foreign coal producers, and indirectly with other energy producers throughout the U.S. and, for our export sales, internationally. In addition to the price of coal, coal quality, and transportation costs, demand for coal also has a significant impact on our ability to compete domestically and internationally for coal sales. Demand for coal depends upon a number of factors, including:

- general economic conditions and weather patterns, both of which are significant contributors to the demand for electricity;
- delivered prices for coal, including the relative costs of transportation, such as ocean freight rates, from our mine site and competing mines;
- availability and cost of alternative fuel sources, such as natural gas;
- technological developments;
- environmental, tax, and other governmental policies and regulations, including EPA regulations; and
- currency exchange rate fluctuations impacting our export sales.

Demand for U.S. coal has fluctuated over the last decade because of these and other factors. A decline in domestic demand for coal, or a decline in foreign demand for U.S. coal, could cause additional significant competition among coal producers and downward pressure on coal prices. Furthermore, overcapacity and increased production in the future, similar to the activities that occurred during the mid 1970s and early 1980s, could result in additional production capacity throughout the industry, causing increased competition and lower coal prices, materially reducing our revenue, profitability, cash flows, and liquidity.

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 has made natural gas more competitive against coal and resulted in utilities switching from coal to natural gas. Sustained low natural gas prices may also cause utilities to phase out or close existing

coal-fired power plants or reduce or eliminate construction of any new coal-fired power plants, which could have a material adverse effect on demand and prices received for our coal.

Legislation requiring the use and dispatch of alternative energy sources and fuels or legislation providing financing or incentives to encourage continuing technological advances and deployment in this area could further enable alternative energy sources to become more competitive with coal. If alternative energy sources, such as hydroelectric, wind or solar, become more cost-competitive, demand for coal could decrease and cause a decrease in the price of coal.

If we do not grow our logistics revenue and export sales at favorable prices, we may incur losses in our logistics business and be subject to significant take-or-pay obligations.

A growing percentage of our coal sales in recent years has been into export markets in Asia, and we are seeking to make additional export sales to Asia and potentially other international locations. Our ability to grow our export sales revenue and logistics margins depends on a number of factors, including the price we receive for our coal and our logistics services, the existence of sufficient and cost-effective export terminal capacity for the shipment of thermal coal to foreign markets, and demand by customers in Asia and in other potential export markets for PRB coal.

International customer demand for PRB coal, and the prices those customers may be willing to pay for PRB coal and related transportation services provided by our logistics business, can be affected by a variety of matters, including supplier diversity and security considerations, economic conditions and demand for electricity in the relevant markets, international energy and tax policies and regulatory requirements, and availability and pricing for thermal coal delivered from alternative international coal basins. Further, our export sales are priced relative to the international Newcastle benchmark price index, which is volatile. For example, on December 31, 2013, spot Newcastle prices were $85.44 per tonne. As of December 31, 2014, spot Newcastle prices decreased significantly to $63.53 per tonne. Fluctuations in this index may be affected by a wide range of international supply and demand factors, including those listed above. Our export sales may also be negatively impacted by currency exchange rate fluctuations that make coal from other countries more economical than PRB coal and provide competitive advantages to non-U.S. producers when the U.S. dollar is strong in comparison to those foreign currencies. For example, the Newcastle benchmark price index is denominated in U.S. dollars. Since 2013, the conversion rate of U.S. dollars to Australian dollars increased from 0.96 at January 1, 2013 to 1.23 at December 31, 2014. If demand for exports declines or we are unable to secure a favorable price for the export of our coal and logistics services, our cash flows, profitability, liquidity, and results of operations may be materially adversely affected.

At present, there is limited terminal capacity for the export of PRB coal to foreign markets. Our access to existing and any future terminal capacity, including the proposed Gateway Pacific Terminal and proposed Millennium Bulk Terminal in which we have options for potential future 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 North American coal producers for access to limited terminal capacity, among other factors. If we fail to maintain terminal capacity, or are denied access to existing or any future terminals for the export of our coal on commercially reasonable terms, or at all, our results from our export transactions will be materially adversely affected.

In addition, we have significant long-term take-or-pay contracts for rail and terminal capacity related to our logistics services for export sales. These contracts require us to pay for a minimum quantity of coal to be transported on the railway or through the terminal regardless of whether we sell any coal or the prices we receive for our coal or logistics services. If we fail to make sufficient export sales to meet our minimum obligations under these take-or-pay contracts, we are still obligated to make payments to the railway or terminal, which could have a negative impact on our cash flows, profitability and results of operations. As of December 31, 2014, we had take-or-pay obligations of $691.5 million that could be potentially payable through 2024 if we fail to meet our minimum shipment obligations.

Our long-term growth may be materially adversely impacted if economic, commercially available carbon capture technology for power plants is not developed and adopted in a timely manner.

Federal or state laws or regulations may be adopted that would impose new or additional limits on the emissions of GHGs, including, but not limited to, CO_2 from electric generating units using fossil fuels such as coal or natural gas. In order to comply with such regulations, electric generating units using fossil fuels may be required to implement carbon capture technology. For example, the EPA has released a proposed rule that would establish, for the first time, new source performance standards under the federal Clean Air Act for CO_2 emissions from new fossil fuel-fired electric utility generating power plants. Carbon capture and sequestration is one of the technologies new, coal-fired power plants can employ to meet the proposed standard. However, there is currently no large-scale use of carbon capture and storage technologies in domestic coal-fired power plants, and as a result, there is a risk that such technology may not be commercially practical in limiting

Table of Contents

emissions as otherwise required by the proposed rule or similar rules that may be proposed in the future. If such legislative or regulatory programs are adopted, and economic, commercially available carbon capture technology for power plants is not developed or adopted in a timely manner, it would negatively affect our customers and would reduce the demand for coal as a fuel source, causing coal prices and sales of our coal to decline, perhaps materially.

Our business, financial condition and results of operations may be adversely affected by unfavorable global or U.S. economic and market conditions.

In recent years, the global economic downturn, particularly with respect to the U.S. economy and various European and Asian economies, and global financial and credit market disruptions had a negative impact on us and the coal industry generally. For example, the economic downturn in recent years has led to an oversupply of coal in the marketplace and depressed prices.

Furthermore, because we typically seek to enter into long-term arrangements for the sale of a substantial portion of our coal, the average sales price we receive for our coal may lag behind any general economic recovery. Future economic downturns or further disruptions in the financial and credit markets could negatively impact our business, financial condition and results of operations.

Decreases in U.S. and global demand for electricity due to economic, weather or other conditions could negatively affect coal prices.

Our coal customers primarily use our coal as fuel for electricity generation. Overall economic activity and the associated demands for power by industrial users can have significant effects on overall electricity demand and can be caused by a number of factors. An economic slowdown can significantly slow the growth of electricity demand and could result in reduced demand for coal. For example, declines in the rate of international economic growth in countries such as China, India or other developing countries could impact the demand for U.S. coal and result in an oversupply of coal in the marketplace. Weather patterns can also greatly affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increase generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand, which allows generators to choose the sources of power generation when deciding which generation sources to dispatch. For example, the unusually warm winter of 2011/2012 led to low gas heating demand at a time of increasing gas production. This in turn led to low gas prices and substitution of gas for coal. When gas prices rose, this substitution of PRB coal decreased, but not enough to offset the increased utility coal stockpiles during this period, which lead to a reduction in utility coal contracting and depressed coal prices. Decreases in coal demand for these or other reasons could cause downward pressure on coal prices and would negatively impact our results of operations.

Our coal mining operations are subject to operating risks, which could result in materially increased operating expenses and decreased production levels.

We mine coal at surface mining operations located in Wyoming and Montana. Our coal mining operations are subject to a number of operating risks. These operating risks include, among others:

- poor mining conditions resulting from geological, hydrologic, ground or other conditions, which may cause instability of highwalls or spoil-piles or cause damage to nearby infrastructure such as roads, power lines, railways and gas pipelines;

- critical mining and plant equipment failures, unexpected maintenance problems or damage from fire, flooding or other events;

- adverse weather and natural disasters, such as heavy rains, flooding, droughts, dust and other natural events affecting operations, transportation or customers;

- the unavailability of raw materials, equipment (including heavy mobile equipment) or other critical supplies such as tires and explosives, fuel, lubricants and other consumables of the type, quantity and/or size needed to meet production expectations;

- the capacity of, and proximity to, rail transportation facilities and rail transportation delays or interruptions, including derailments;

- 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; and

- a major incident at a mine site that causes all or part of the operations of a mine to cease for some period of time.

Table of Contents

Because we maintain very little produced coal inventory, disruptions in our operations due to these or other risks could negatively impact or even halt production and shipments, significantly increase the cost of mining and impact our ability to meet our contractual obligations to customers and others, which could have a material adverse effect on our results of operations. We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance regarding the extent, if any, to which these risks would be covered by our insurance policies.

The availability and reliability of sufficient transportation capacity and increases in transportation costs could materially adversely affect the demand for our coal or impair our ability to supply coal to our domestic and export customers.

Transportation costs represent a significant portion of the total cost of coal for our domestic and export customers. The cost and availability of transportation is a key factor in a customer s purchasing decision and impacts our coal sales and the price we receive for our coal. Coal could become a less competitive source of energy if the costs of transportation increase or the availability or capacity of rail lines or export terminals is insufficient. Transportation costs and availability could also make our coal less competitive than coal produced from other regions.

Our ability to sell coal to our customers depends primarily upon third-party rail systems and export terminals. If our customers are unable to obtain transportation services, or to do so on a cost-effective basis, our business and growth strategy could be adversely affected. Alternative transportation and delivery systems are generally inadequate and not suitable to handle the quantity of our shipments or to ensure timely delivery to our customers. Export terminals, including the proposed Gateway Pacific Terminal and proposed Millennium Bulk Terminal in which we have options for potential future capacity, are also subject to permit requirements and challenges from environmental organizations which may make it complicated or expensive to expand existing terminal capacity or open new export terminals in a timely and cost-effective manner. In addition, much of the PRB is served by two rail carriers, and the Northern PRB is only serviced by one rail carrier. The loss of sufficient and reliable access to rail capacity in the PRB, as we have experienced in recent years, could create disruption until this access was restored; significantly impairing our ability to supply coal and resulting in materially decreased revenue. Similarly, being denied access to an export terminal could significantly affect our export sales, materially decreasing our logistics revenue and growth opportunities. Our ability to open new mines or expand existing mines may also be affected by the access to, and availability and cost of rail, export terminal or other transportation systems available for servicing these mines.

Typically, our mine customers contract and pay directly for transportation of coal from the mine or port to the point of use. However, for contracts with our logistics customers, we are required to enter into transportation agreements pursuant to which we arrange and pay for all rail transport, terminal, and for our international customers, demurrage charges. As the volume of deliveries coordinated to customer contracted destinations increases, so do our costs and risks. Our ability to supply coal to our customers and our customers ability to take our coal may be impacted by the disruption of these transportation services because of weather-related problems; mechanical difficulties; maintenance shut-downs; environmental, political and regulatory issues; train derailment; bridge or structural concerns; infrastructure damage, whether caused by ground instability, accidents or otherwise; strikes; lock-outs; lack of fuel or maintenance items; fuel costs; accidents; terrorism or domestic catastrophe or other events. For example, in the spring and summer of 2011, the Midwest region experienced severe flooding which disrupted rail service to mines in the PRB and affected the ability of those customers who were impacted by the flooding to take coal deliveries. During 2014, we also experienced rail interruptions due to increased competition for rail crews from crude oil and grain shipments, which negatively impacted our shipments and financial results. Any similar disruption in the future could negatively impact our results of operations.

If we are unable to acquire or develop additional coal reserves that are economically recoverable, our future profitability may be reduced and our future success and growth may be significantly impacted.

Our profitability depends substantially on our ability to mine, in a timely and cost-effective manner, coal reserves that possess the quality characteristics our customers desire. Because our reserves decline as we mine our coal, our future success and growth depend upon our ability to acquire additional coal that is economically recoverable. We primarily acquire additional coal through the federal competitive leasing process, but we also enter into state and private coal leases as well as acquire coal from private third parties. If we fail to acquire or develop additional reserves, our existing reserves will eventually be depleted. Our ability to obtain additional coal reserves in the future could also be limited by a number of factors, any of which could impact our business and growth strategy, including:

- the availability of cash we generate from our operations;
- available financing and restrictions under our debt instruments;
- competition from other coal companies for properties;

Table of Contents

- lack of suitable acquisition or LBA opportunities; or

- delay in the federal leasing process caused by third-party legal challenges or the inability to acquire coal properties or federal coal leases on commercially reasonable terms.

Any significant delay in acquiring reserves could negatively impact our production rate. We will need to acquire additional coal reserves that can be mined on an economically recoverable basis to maintain our production capacity and competitive position. We may be unable to mine future reserves at profitability levels achieved at times in the past. The price we receive for our coal also impacts how economically we can recover our existing coal. Our ability to develop economically recoverable reserves will be materially adversely impacted if prices for coal sold remain depressed or decrease significantly.

Because most of the coal in the vicinity of our mines is owned by the U.S. federal government, our future success and growth would be affected if we are unable to acquire or are significantly delayed in the acquisition of additional reserves through the federal competitive leasing process.

The U.S. federal government owns most of the coal in the vicinity of our mines. Accordingly, the federal competitive leasing process is our primary means of acquiring additional reserves. There is no requirement that the federal government must lease its coal. Furthermore, there is no requirement that the federal government must give preference to any LBA applicant which means our bids for federal coal leases may compete with other coal producers bids. Over time, federal coal leases have become increasingly more competitive and expensive to obtain, and the review process to submit an LBA for bid continues to lengthen. We expect this trend to continue. The increasing size of potential LBA tracts may make it easier for new mining operators to enter the market on economic terms and may, therefore, increase competition for federal coal leases. Increased opposition from non-governmental organizations and other third parties may also lengthen, delay or complicate the LBA process. In order to win a lease in the LBA process and acquire additional coal, our bid for a coal tract must meet or exceed the fair market value of the coal based on the internal estimates of the BLM, which is not published. Any failure or delay in acquiring a coal lease through the LBA process, or the inability to do so on economic terms, could cause our production to decline, materially adversely affecting our business, cash flows and results of operations. For example, the West Antelope II leases we were awarded through the LBA process in 2011 were subject to legal challenges against the BLM and the Secretary of the Interior by environmental organizations. Though these challenges were unsuccessful and the plaintiffs abandoned their efforts for appeal, our nominations or lease applications may be subject to similar delays or challenges, which may result in difficulties in obtaining leases or impact our ability to mine the coal subject to those leases and/or delay our access to mine the coal.

The LBA process also requires us to acquire rights to mine from certain surface owners overlying the coal before the federal government will agree to lease the coal. Surface rights in the PRB are becoming increasingly more difficult and costly to acquire. Certain federal regulations provide a specific class of surface owners, also known as qualified surface owners (QSO), with the ability to prohibit the BLM from leasing its coal. For example, in connection with an LBA that we previously nominated for our Cordero Rojo Mine, the BLM indicated that certain surface owners satisfy the regulatory definition of QSO. If a QSO owns the land overlying a coal tract, federal laws prohibit us from leasing the coal tract without first securing surface rights to the land, or purchasing the surface rights from the QSO. This right of QSOs allows them to exercise significant influence over negotiations to acquire surface rights and can delay the LBA process or ultimately prevent the acquisition of coal underlying their surface. If we are unable to successfully negotiate access rights with QSOs at a price and on terms acceptable to us, we may be unable to acquire federal coal leases on land owned by the QSO. Our profitability could be materially adversely affected if the prices to acquire land owned by QSOs increase.

If we are unable to acquire surface rights to access our coal, we may be unable to obtain a permit or otherwise be unable to mine coal we own and may be required to employ expensive techniques to mine around those sections of land we cannot access in order to access other sections of coal reserves.

After we acquire coal we are required to obtain a permit to mine the coal through the applicable state agencies before we are allowed to begin mining. In part, the permitting requirements provide that, under certain circumstances, we must obtain surface owner consent if the surface estate has been split from the mineral estate, which is commonly known as a split estate. We have in the past and may in the future be required to negotiate with multiple parties for the surface access that overlies coal we acquired. If we are unable to successfully negotiate surface access with any of these surface owners, or do so on commercially reasonable terms, we may be denied a permit to mine some of the coal we have acquired or may find that we cannot mine the coal at a profit or at all. If we are denied a permit, this would create significant delays and restrictions in our mining operations and materially adversely impact our business and results of operations. Furthermore, if we determine to alter our plans to mine around the affected areas, we could incur significant additional costs to do so, which

Table of Contents

could increase our operating expenses considerably and could materially adversely affect our results of operations. Failure to successfully negotiate access for surface rights overlying coal that we control in a timely manner may also result in significant accounting charges, which could have a material adverse impact on our results of operations.

Defects in title or the loss of a leasehold interest in, or superior or conflicting property rights impacting, reserves or surface rights could limit our ability to mine our coal reserves and adversely impact our operations and costs.

A title defect on any lease, whether private or through a governmental entity, or the surface rights related to any of our reserves could adversely affect our ability to mine the associated coal reserves. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to properties leased from private third parties is not usually fully verified until we make a commitment to develop a property, which may not occur until we have obtained the necessary permits and completed exploration of the property. Title or other defects in surface rights held by us or other third parties could impair our ability to mine the associated coal reserves or cause us to incur unanticipated costs.

In addition, these leasehold interests may be subject to superior property rights of other third parties. The federal government leases many different mineral rights in addition to coal, such as coalbed methane, natural gas and crude oil rights. Some of these minerals are located on, or are adjacent to, some of our coal and LBA areas, potentially creating conflicting interests between us and the lessees of those interests and may affect our ability to operate as planned if our title is not superior or cost-effective arrangements cannot be timely negotiated. We are regularly in negotiations with third parties in an effort to address potentially conflicting mineral development. These negotiations may not be effective. In that event, our mine plans, future costs and production rates may be adversely impacted. Anticipated oil and gas development is expected to increase the frequency of these potential conflicts.

Further, the majority of our coal interests are acquired by lease from state or federal governments. If any of our leases are terminated, for lack of diligent development or otherwise, we would be unable to mine the affected coal and our business and results of operations could be materially adversely affected.

We may not recover our investments in our mining, exploration, port access rights, and other assets, which may require us to recognize impairment charges related to those assets.

The value of our assets may be adversely affected by numerous uncertain factors, some of which are beyond our control, including:

- unfavorable changes in the economic environments in which we operate;

- unfavorable regulatory or legal developments impacting our industry;

- lower-than-expected domestic and international demand and coal pricing;
- technical and geological operating difficulties;
- an inability to economically extract our coal reserves;
- unanticipated increases in operating costs; and
- an inability to obtain additional export terminal capacity due to extensive permit requirements and challenges from environmental organizations.

These may cause us to fail to recover all or a portion of our investments in those assets and may trigger the recognition of impairment charges in the future, which could have a substantial adverse impact on our results of operations. Because of the volatile nature of U.S. and international coal markets, it is reasonably possible that our current estimates of projected future cash flows from our mining assets may change in the near term, which may result in the need for adjustments to the carrying value of mineral rights, port access contract rights, goodwill, and other assets.

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

Acquisitions are a potentially important part of our long-term growth strategy, and we may pursue acquisition opportunities in the future in the U.S. and other jurisdictions. If we fail to accurately estimate the future results and value of an acquired business or are unable to successfully integrate the businesses or properties we acquire, our business, financial condition or results of operations could be negatively affected, and we may be unable to grow our business. Acquisition transactions involve various risks, including:

Table of Contents

- uncertainties in assessing the strengths and potential profitability, and the related weaknesses, risks, contingent and other liabilities, of acquisition candidates;
- changes in business, industry, market or general economic conditions that affect the assumptions underlying our rationale for pursuing the acquisition;
- the inability to achieve identified operating and financial synergies anticipated to result from an acquisition;
- the potential loss of key customers, management or employees of an acquired business;
- the nature and composition of the workforce, including the acquisition of a unionized workforce;
- diversion of our management s attention from other business concerns;
- regulatory challenges for completing and operating the acquired business, including opposition from environmental groups or regulatory agencies;
- environmental or geological problems in acquired coal properties, including factors that make the coal unsuitable for intended customers (due to ash, heat value, moisture, or contaminants), that make the coal more expensive to mine, or delay our ability to mine;
- inability to acquire sufficient surface rights to enable extraction of coal resources;
- outstanding permit violations associated with acquired assets;
- difficulties or unexpected issues arising from our evaluation of internal control over financial reporting of the acquired business;

- risks related to operating in new jurisdictions or industries, including increased exposure to foreign government and currency risks with respect to any international acquisitions; and

- unanticipated liabilities associated with the acquired companies.

Any one or more of these factors could cause us not to realize the benefits we might anticipate from an acquisition. Moreover, any acquisition opportunities we pursue could materially increase our liquidity and capital resource needs and may require us to incur indebtedness, seek equity capital or both. We may not be able to satisfy these liquidity and capital resource needs on acceptable terms or at all. In addition, future acquisitions could result in our assuming significant long-term liabilities relative to the value of the acquisitions.

We may be unable to obtain, maintain or renew permits or licenses necessary for our operations, which would materially reduce our production, cash flows and profitability.

As a mining company, we must obtain a number of permits and licenses from various federal, state and local agencies and regulatory bodies that impose strict regulations on environmental and operational matters in connection with our coal operations, including restricting the number of tons we may mine under our air quality permits. 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 make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing operations, impact the development of future mining operations or restrict the amount of our production. 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 EISs prepared in connection with applicable regulatory processes. These groups may also participate in the permitting and licensing process, including bringing citizens lawsuits to challenge the issuance of permits, the validity of an EIS or performance of mining activities, which can create delay and uncertainty in acquiring permits and mining the coal underlying our leases. For example, the EIS and other regulatory matters associated with the West Antelope II LBAs were legally challenged by several non-governmental organizations. Though these challenges were unsuccessful and the plaintiffs abandoned their efforts for appeal, if our permits or licenses are not issued or renewed in a timely fashion or at all, or if permits issued or renewed are conditioned in a manner that restricts our ability to efficiently and economically conduct our mining activities, we could suffer a material reduction in our production, an impairment of our mineral rights, and our cash flows or profitability could be materially adversely affected.

Table of Contents

Existing and future legislation, treaties, regulatory requirements and public concerns relating to GHG emissions could negatively affect our customers and reduce the demand for coal as a fuel source, causing coal prices and sales of our coal to materially decline.

There are three important sources of GHGs associated with the coal industry. The end use of our coal in electricity generation is a source of GHGs. Combustion of fuel for mining equipment used in coal production is another source of GHGs. In addition, coal mining can release methane, a GHG, directly into the atmosphere. These emissions from coal consumption and production are potentially subject to regulation as part of regulatory initiatives to address global climate change and global warming. Various international, federal, regional and state proposals are being considered to limit emissions of GHGs, including possible future U.S. treaty commitments, new federal or state legislation that may, among other things establish a cap-and-trade regime, and regulation under existing environmental laws by the EPA and other regulatory agencies. Future regulation of GHG emissions may require additional controls on, or the closure of, coal-fired power plants and industrial boilers or may restrict the construction of new coal-fired power plants. For example, the EPA recently proposed new source performance standards for GHG emissions for new coal and oil-fired power plants, which could require partial carbon capture and sequestration. See Risks Related to Our Business and Industry Our long-term growth may be materially adversely impacted if economic, commercially available carbon capture technology for power plants is not developed and adopted in a timely manner. These regulatory initiatives may increase our costs and decrease demand and pricing for our coal and logistics services, and may lead to increased demand for domestic electricity fired by natural gas because gas-fired plants are cheaper to construct, and permits to construct these plants can be easier to obtain.

The permitting of new coal-fired power plants has also recently been contested, at times successfully, by state regulators and environmental organizations due to concerns related to GHG emissions from the new plants. Private litigation has also been brought against industry participants based on GHG-related concerns. The U.S. Supreme Court held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, but tort-type liabilities and other GHG-related claims against utilities and energy producers may be asserted. For example, in 2011 residents and property owners along the Mississippi Gulf coast filed litigation against approximately 90 companies in energy, fossil fuels and chemical industries, including PRB and other domestic coal companies, alleging that the defendants caused the emission of GHGs that contributed to global warming, which in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina in 2005, which combined to destroy the plaintiffs property. The lawsuit was dismissed by the Federal District Court in 2012 and the dismissal was affirmed by the Fifth Circuit Court of Appeals in May 2013. However, if other GHG-related litigation is successful, the coal industry and our company may be materially adversely impacted. See Item 1 Business Environmental and Other Regulatory Matters Global Climate Change.

Extensive environmental laws, including existing and potential future legislation, treaties and 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.

The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, CSAPR initially requires 28 states in the Midwest and eastern seaboard of the U.S. to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR and ordered the EPA to continue enforcing CAIR. More recently, the U.S. Supreme Court reversed the D.C. Circuit s vacation of CSAPR, and the D.C. Circuit has granted a request by the EPA to lift the stay of the rule. Subsequently, in November 2014, the EPA issued an interim final rule reconciling the CSAPR rule with the Court s order to lift the stay, calling for Phase 1 implementation in 2015 and Phase 2 implementation in 2017. CSAPR is one of a number of significant regulations that the EPA has issued or expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. These rules include the EPA s new requirements for CCR management, which were finalized in December 2014 and further regulate the handling of wastes from the combustion of coal. In addition, in March 2013, the EPA formally adopted a revised final rule to reduce emissions of toxic air pollutants from power plants. Specifically, these MATS for power plants will reduce emissions from new and existing coal- and oil-fired electric utility steam generating units. The D.C. Circuit upheld various portions of the MATS rulemaking in two separate decisions issued in March and April 2014, respectively. In November 2014, the U.S. Supreme Court granted certiorari to review the D.C. Circuit decision. The litigation does not include provisions for a stay and the timeline for general compliance with the standards remains at April 2015. We continue to evaluate the status of these and other regulatory programs as well as the effects they may have on our business and our results of operations, financial condition or cash flows.

Considerable uncertainty is associated with air emissions initiatives. New regulations are in the process of being developed, and many existing and potential regulatory initiatives are 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

Table of Contents

these limitations will likely require significant emissions control expenditures for many coal-fired 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. Any switching of fuel sources away from coal, closure of existing coal-fired power plants, or reduced construction of new coal-fired power 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. See Item 1 Business Environmental and Other Regulatory Matters Endangered Species Act.

Our mining operations are subject to extensive environmental, health, safety or other laws and regulations that could materially increase our costs or limit our ability to produce and sell coal, including the potential listing of the greater sage-grouse as a threatened species.

Our mining operations are subject to extensive federal, state and local environmental, health and safety, transportation, labor and other laws and regulations. Examples include those relating to:

- employee health and safety;
- emissions to air and discharges to water;
- plant and wildlife protection, including the potential classification of the sage-grouse and the mountain plover as endangered or threatened species. See Item 1 Business Environmental and Other Regulatory Matters Clean Air Act ;
- the reclamation and restoration of properties after mining or other activity has been completed;
- remediation of contaminated soil, surface and groundwater; and
- the effects of operations on surface water and groundwater quality and availability.

Furthermore, we must compensate employees for work-related injuries through our workers compensation insurance funds. The erosion through tort liability of the protections we are currently provided by workers compensation laws could increase our liability for work-related injuries.

MSHA is responsible for monitoring compliance with federal mine health and safety standards at our mines. MSHA has various enforcement tools that it can use, including the issuance of citations resulting in monetary penalties and orders of withdrawal from a mine or part of a mine. Since the April 2010 explosion at Massey Energy Company s (now Alpha Natural Resources) Upper Big Branch Mine, increased scrutiny has been placed on the mining industry and has had significant impacts on the regulation of mine safety matters at the federal and state levels. For example, federal authorities have announced additional targeted inspections of coal mines to evaluate several safety concerns, including the accumulation of coal dust and the proper ventilation of gases such as methane. Federal authorities are also frequently proposing 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 and/or health and safety requirements may be replicated in the states in which we operate and could increase our operating costs or otherwise prevent, delay or reduce our planned production, any of which could adversely affect our financial condition, results of operations and cash flows.

The costs, liabilities and requirements associated with complying with these requirements are often significant and time-consuming and may delay commencement or continuation of exploration or production. These factors could have a material adverse effect on our results of operations, cash flows and financial condition. New legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations may also require us to change operations significantly or incur increased costs. For example, in November 2011, several environmental groups sued the EPA in Washington federal court to compel the EPA to include coal mines on the list of stationary sources governed by air pollution performance standards. In that case, the Court denied the groups rulemaking petition, and in July 2014, also denied a petition seeking a rehearing of the case en banc. Any imposition of air emission standards on coal mines or any other such changes could have a material adverse effect on our financial condition and results of operations.

Because of the extensive regulatory environment in which we operate, we cannot assure complete compliance with all laws and regulations. Failure to comply with these laws may result in significant costs to us to correct such violations, as well as civil or criminal penalties and limitations or shutdowns of our operations. These laws and regulations may also significantly impair our ability to conduct our mining operations or result in increased operating costs.

Table of Contents

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

Federal and state regulatory agencies have the authority following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this were to occur, 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 and our take-or-pay contracts related to our export terminals may 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.

Our operations may affect the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, any of which could result in material liabilities to us.

Our operations use hazardous materials and generate hazardous and non-hazardous wastes. In addition, many of the locations that we own, lease or operate were used for coal mining and/or involved the generation, use, storage and disposal of hazardous substances either before or after we were involved with these locations. We may be subject to claims under federal and state statutes and/or common law doctrines 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. These claims may arise, for example, out of current or former conditions at sites that we own, lease or operate currently, as well as at sites that we or predecessor entities owned, leased or operated in the past, and at contaminated third-party sites at which we have disposed of hazardous substances and waste. As a matter of law, and despite any contractual indemnity or allocation arrangements or acquisition agreements to the contrary, our liability for these claims may be joint and several, so that we may be held responsible for more than our share of any contamination, or even for the entire share.

We may incur material costs and liabilities resulting from claims for damage 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 adversely affected.

Significant increases in taxes we pay on the coal we produce at our mine sites or deliver through our logistics business, such as royalties or severance and production taxes, including as a result of governmental audits or regulatory or interpretive changes, could materially and adversely affect our profitability.

We pay federal, state and private royalties and federal, state and county severance and production taxes on the coal we sell. A substantial portion of our royalties and severance and production taxes are levied as a percentage of gross revenue with the remaining levied on a per ton basis. For example, we pay production royalties of 12.5% of gross proceeds to the federal government on all coal sold at the mine sites. We incurred royalties and severance and production taxes totaling $331.6 million and $327.9 million for the years ended December 31, 2014 and 2013, respectively. The calculations used to determine royalty or severance and production tax payments can be complex and subject to interpretation, making it difficult in some cases to estimate such payments. If royalties or severance and production tax rates were to significantly increase, or if the methodology by which the government agencies assess royalties or severance and production tax rates (including with respect to non-arms length sales) materially changes, our results of operations could be materially adversely affected. See Note 18 of Notes to Consolidated Financial Statements in Item 8. Examples of this could include:

- the federal government has recently proposed to significantly alter the method for valuing royalty payments for non-arms length sales, which, if enacted, could materially adversely affect our profitability and cash flows related to our logistics business;

- if a state government were to increase this tax or any other tax applicable to our operations in that state, our profitability could be reduced and our results of operations negatively affected;

- if we are required to make additional payments (including related interest and penalties) as a result of pending or future governmental audits, our results of operations would be negatively impacted; and

- since pending audits can date back many years, associated penalties and interest can be significant.

Table of Contents

Failure to maintain our surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and materially adversely affect our ability to mine or lease coal.

Federal and state laws require us to secure the performance of certain long-term obligations, such as mine closure costs, reclamation costs, and federal and state workers compensation costs, including black lung. The primary methods we use to meet those obligations are to provide a third-party surety bond or a letter of credit. As of December 31, 2014, we had outstanding surety bonds with third parties of $448.9 million and were self-bonded for $200 million. Surety bond issuers and holders may demand additional collateral, unfavorable terms or higher fees. In addition, we could fail to meet the requirements to continue to qualify for self-bonding which would result in us needing to increase our surety bonds which may not be available to us at attractive terms. Our failure to retain, or inability to acquire, surety bonds or letters of credit or to provide a suitable alternative could adversely affect our ability to mine or lease coal, which would materially adversely affect our business and results of operations. 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 bonds and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of any credit arrangements then in place.

Furthermore, while we have maintained a history of timely payments related to our LBAs, if we are unable to maintain our good payer status, we would be required to seek bonding for any remaining payments, which could adversely impact our cash flows and the amount of availability under our credit facility, if such bonds could be obtained at all. In addition, the BLM has proposed rule changes pursuant to the 2005 Energy Policy Act that, among other things, would require a 5-year history to take advantage of bonus bid bonding waivers for lessees with favorable histories of timely payments of bonus bids and royalties, which could result in a requirement for our company to provide lease bonus bid bonds.

In addition, if federal or state laws are amended to require certain forms of financial assurance other than surety bonds, such as letters of credit, obtaining them, if we could obtain them at all, could have a material negative impact on our liquidity and results of operations.

Our business requires substantial capital expenditures, which we may be unable to provide.

Our business plan and strategy are dependent upon our acquisitions of additional reserves, which require substantial capital expenditures. We also require capital for, among other purposes:

- acquisition of surface rights;
- equipment and the development of our mining operations;
- capital renovations;

- export terminal development projects;
- maintenance and expansions of plants and equipment; and
- compliance with environmental laws and regulations.

To the extent that cash on hand, cash generated internally and cash available under our credit facility are not sufficient to fund capital requirements, we will require additional debt and/or equity financing. However, additional debt or equity financing may not be available to us or, if available, may not be available on satisfactory terms. Additionally, our debt instruments may restrict our ability to obtain such financing. If we are unable to obtain additional capital, we may not be able to maintain or increase our existing production rates and we could be forced to reduce or delay capital expenditures or change our business strategy, sell assets or restructure or refinance our indebtedness, all of which could have a material adverse effect on our business or financial condition.

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

SMCRA and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining. We accrue for the costs of current mine disturbance and final mine closure. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our experience. The amounts recorded are dependent upon a number of variables, including the estimated future asset retirement costs, estimated proven reserves, assumptions involving profit margins of third-party contractors, inflation rates, discount rates and assumed credit-adjusted,

Table of Contents

risk-free rates. Furthermore, these obligations are unfunded. If our accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be materially adversely affected.

Increases in the cost of raw materials and other industrial supplies, or the inability to obtain a sufficient quantity of those supplies, could increase our operating expenses, disrupt or delay our production and materially adversely affect our profitability.

We use considerable quantities of explosives, petroleum-based fuels, tires, steel and other raw materials, as well as spare parts and other consumables in the mining process. If the prices of steel, explosives, tires, petroleum products or other materials increase significantly or if the value of the U.S. dollar declines relative to foreign currencies with respect to certain imported supplies or other products, our operating expenses will increase, which could materially adversely impact our profitability. Additionally, a limited number of suppliers exist for certain supplies, such as explosives and tires, as well as certain mining equipment, and any of our suppliers may divert their products to buyers in other mines or industries or divert their raw materials to produce other products that have a higher profit margin. For example, we previously experienced a severe tire shortage in 2005 that lasted several years. This tire shortage increased the direct cost of tires and caused us to change our operating practices to increase tire life. Shortages in raw materials used in the manufacturing of supplies and mining equipment, which, in some cases, do not have ready substitutes, or the cancellation of our supply contracts under which we obtain these raw materials and other consumables, could limit our ability to obtain these supplies or equipment. As a result, we may not be able to acquire adequate replacements for these supplies or equipment on a cost-effective basis or at all, which could also materially increase our operating expenses or halt, disrupt or delay our production.

Furthermore, operating expenses at our mining locations are sensitive to changes in certain variable costs, particularly diesel fuel prices, which is our largest variable cost after personnel costs. Our profitability depends on our ability to adequately control our costs, particularly with respect to diesel fuel. Any increase in the price we pay for diesel fuel will have a negative impact on our results of operations. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Years Ended December 31, 2014, 2013 and 2012 Cost of Product Sold and Item 7A Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risks.

Our hedging activities for diesel fuel may prevent us from benefiting from cost price decreases.

We enter into derivative financial instruments to help manage our exposure to market price changes to our diesel fuel costs, which are indexed to the WTI crude oil price as quoted on the New York Mercantile Exchange. As such, the nature of the derivative financial instruments does not directly offset market changes to our diesel fuel costs.

At December 31, 2014, we had purchased 2015 call options for approximately 0.7 million WTI crude oil barrels and 2015 put options for approximately 0.4 million WTI crude oil barrels, which approximates 100% and 60% of our expected 2015 diesel fuel usage. While our hedging strategy provides us protection in the event of crude oil price increases, it reduces our benefit when crude oil prices decrease below our floor and may require substantial payments by us to settle our financial instruments. See Item 7A Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk and Note 7 of Notes to Consolidated Financial Statements in Item 8.

Our hedging activities for coal sales prices may result in a negative impact from sales price changes.

As part of our logistics business, we enter into derivative financial instruments in the form of international coal forward contracts to help manage our exposure to future coal sales prices by fixing a price now for a future contracted coal delivery. This type of hedge is designed to protect us from any price decreases. While our hedging strategy provides us some degree of protection in the event future coal prices decrease it may also prevent us from benefiting if future coal prices increase above our hedged price and may require substantial payments by us to settle our financial instruments. As of December 31, 2014, we had coal forward contracts for approximately 0.6 million tons, which will settle in 2015 and 2016.

In addition, we use domestic coal futures contracts to help manage our exposure to market changes in domestic coal prices. This type of hedge is designed to benefit us when prices change relative to our current open positions. If there are significant and extended unfavorable price movements against our positions, our earnings and liquidity could be negatively impacted. As of December 31, 2014, we held domestic coal futures contracts for approximately 2.1 million tons, which will settle in 2015 and 2016. See Item 7A Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk and Note 7 of Notes to Consolidated Financial Statements in Item 8.

Table of Contents

Changes in the fair value of derivative financial instruments that are not accounted for as a hedge could cause volatility in our earnings.

From time to time, we enter into certain derivative financial instruments to help manage our exposure to future coal prices, both with respect to our export and domestic sales prices and to rises in our diesel costs. Derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. To the extent these derivative financial instruments do not qualify for hedge accounting or we choose not to designate them for hedge accounting, we are required to record changes in the fair value of these derivative financial instruments in our Consolidated Statement of Operations, resulting in increased volatility in our income in future periods.

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

We base our estimates of reserves on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers, which are reviewed by an independent consultant every two years. Our estimates of proven and probable coal reserves as to both quantity and quality are updated 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, any one of which may vary considerably from actual results. These factors and assumptions include:

- coal characteristics such as Btu and sulfur content;
- 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;
- future coal prices and demand;
- equipment and productivity;
- operating costs, including for critical supplies such as fuel, tires and explosives;
- capital expenditures and development and reclamation costs;

- the percentage of coal ultimately recoverable;

- the effects of regulation, including the issuance of required permits, and taxes, including severance and production taxes and royalties, and other payments to governmental agencies; and

- timing for the development of the reserves.

Any changes to the above factors and assumptions could cause our estimates of the quantities and qualities of economically recoverable coal to vary significantly. Changes to the above factors and assumptions could also materially impact how we classify our reserves based on risk of recovery and our estimates of future net cash flows expected from these properties. Actual production recovered from identified reserve areas and properties, and revenue and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy in our proven and probable reserves estimates could result in decreased profitability from lower than expected revenue and/or higher than expected costs.

The majority of our coal sales contracts are forward sales contracts at fixed prices, which may not reflect favorable then-existing prices for coal or may affect our profitability if we cannot adequately control the costs of production for coal underlying such contracts.

We have historically sold most of our coal under long-term coal sales agreements, which we generally define as contracts with a term of one to five years. For the year ended December 31, 2014, approximately 79% of our revenue was derived from coal sales that were made under long-term coal sales agreements. The prices for coal sold under these agreements are typically fixed for an agreed amount of time. Pricing in some of these contracts is subject to certain adjustments in later years or under certain circumstances, and may be below the current market price for similar type coal at any given time, depending on the time frame of the contract.

As a consequence of the substantial volume of our forward sales, our ability to capitalize on near term rises in coal prices is limited. We have less coal available to sell under short-term contracts or on the spot market and we similarly have fewer tons to commit under long-term contracts at higher prices. Our ability to realize higher prices is also restricted if customers elect to purchase additional volumes of coal, which is allowable under some contracts, at contract prices that are lower than spot prices.

Furthermore, to the extent our costs increase but pricing under our long-term coal sales contracts remains fixed, we may be unable to pass such increasing costs on to our customers. If we are unable to control our costs, our profitability may be negatively impacted, adversely affecting our results of operations.

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

For the year ended December 31, 2014, we derived approximately 18% of our total revenue from sales to our three largest customers and approximately 47% of our total revenue from sales to our ten largest customers. We may be unsuccessful in obtaining and renewing coal supply agreements with these customers, and some or all of these customers could discontinue purchasing coal from us. If any of these 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 these customers on terms as favorable to us, the results of our business would be adversely impacted.

Changes in purchasing patterns in the coal industry may make it difficult for us to enter into new contracts with customers, or do so on favorable terms, which could materially adversely affect our business and results of operations.

In past years, we have experienced customers being less willing to enter into long-term coal sales contracts as they continue to adjust to relatively low U.S. natural gas prices, increased price volatility, increased fungibility of coal products, frequently changing regulations and the increasing deregulation of their industry. In addition, the prices for coal in the spot market may be lower than the prices previously set under many of our long-term coal sales agreements. As our contracts with customers expire or are otherwise renegotiated, our customers may be less willing to extend or enter into new long-term coal sales agreements under their existing or similar pricing terms or our customers may decide to purchase fewer tons of coal than in the past.

To the extent our customers shift away from long-term supply contracts, it will be more difficult to predict our future sales. As a result, we may not have a market for our future production at acceptable prices. The prices we receive in the spot market may be less than the contractual price an electric utility is willing to pay for a committed supply. Furthermore, spot market prices tend to be more volatile than contractual prices, which could result in decreased revenue and profitability. For example, as of December 31, 2014, we had approximately 77 million tons of committed sales for 2015 and 47 million tons for 2016, which is below our typical forward sales levels, leaving more coal left to be sold for those periods.

We are exposed to counterparty risk with our customers, trading partners, financial institutions, and other parties with whom we conduct business.

We face an increased risk that we do not receive payment for coal sold and delivered if the creditworthiness of any of our counterparties deteriorates or if any of our counterparties become subject to bankruptcy proceedings. The creditworthiness of these counterparties depends on any number of factors, including the economic volatility and tightening of credit markets, and deregulation of the U.S. utilities markets, allowing utilities to sell their power plants to their non-regulated affiliates or third parties that may have credit ratings that are below investment grade. Competition with other coal suppliers could cause us to extend credit to customers and on terms that could increase the risk of payment default.

We have contracts to supply coal to energy trading and brokering companies, under which they purchase the coal for their own account or resell to domestic and foreign end users. If the creditworthiness of these energy trading and brokering companies declines, this would increase the risk that we may not be able to collect payment for all coal sold and delivered to or on behalf of those companies. Furthermore, if any of these companies seek to renegotiate or cancel sales of coal because of fluctuations in spot prices for coal, issues with their end users accepting the coal or other factors, we may be unable to sell previously anticipated volumes of coal at favorable prices or at all. We also enter into derivative financial instruments with a number of financial institutions. If one or more of these institutions were to default on its future obligation to us, our cash flows and results of operations would be negatively impacted.

In certain circumstances we may be entitled to demand credit enhancements or withhold shipments of coal from these parties if we determine they are not creditworthy. However, these protections may be insufficient to cover our risks or could cause us to resell the coal on the spot market at unfavorable prices or not at all.

Table of Contents

We have significant cash balances, which we may invest from time to time in marketable securities issued by various counterparties including the U.S. government and U.S. government sponsored entities, municipal entities, financial institutions and other corporations. If any of these counterparties fail, we could lose the principal invested with such counterparties, which would materially adversely impact our business, liquidity, and results of operations.

Certain provisions in our coal sales contracts may provide limited protection during adverse economic conditions or may result in economic penalties or suspension upon a failure to meet contractual requirements.

Price adjustment, price re-opener and other similar provisions in our long-term supply contracts may reduce the protection from short-term coal price volatility traditionally provided by these contracts. Most of our contracts with mine customers and some of our contracts with logistics customers contain provisions that allow for the base price of our coal to be adjusted due to new statutes, ordinances or regulations that affect our costs related to performance. Because these provisions only apply to the base price of coal, these terms may provide only limited protection due to changes in regulations. Some of our contracts with mine customers also contain provisions that allow for the purchase price to be renegotiated at periodic intervals. A price re-opener provision is one in which either party can renegotiate the price of the contract, sometimes at pre-determined times. Index provisions allow for the adjustment of the price based on a fixed formula. These provisions may reduce the protection available under long-term contracts from short-term coal price volatility. Our international contracts typically contain a fixed price for the first year of the contract with future years prices to be negotiated at a specific point in time. If the parties fail to satisfactorily negotiate a price, the contract could be terminated. Any adjustment or renegotiations leading to a significantly lower contract price, or a termination of the contract, could result in decreased revenue.

Our coal supply contracts with our mine customers typically contain force majeure provisions allowing temporary suspension of performance by us or our customers during the duration of specified events beyond the control of the affected party. For example, as a result of the very mild 2011/12 winter and low natural gas prices, a greater than normal number of our customers in 2012 sought to reduce the amount of tons delivered to them under our coal sales agreements through contractual remedies, such as force majeure provisions. Our contracts with our mine customers also typically allow our customers to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a force majeure. In addition, our contracts with our international logistics customers generally contain a clause that requires us to pay the demurrage fee charged by the vessel for delays in shipping the coal on behalf of our foreign customers.

Most of our coal supply contracts also contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics, such as heat content, sulfur, ash and ash fusion temperature. Failure to meet these specifications can result in economic penalties, including price adjustments, suspension, rejection or cancellation of deliveries or termination of the contracts. A number of our contracts also contain clauses which, in some cases, may allow customers to terminate the contract in the event of certain changes in environmental laws and regulations.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key personnel.

Our ability to operate our business and implement our strategies depends, in part, on the continued contributions of our executive officers and other key employees. The loss of any of our key senior executives could have a material adverse effect on our business unless and until we find a qualified replacement. A limited number of persons exist with the requisite experience and skills to serve in our senior management positions. We may not be able to locate or employ qualified executives on acceptable terms and our failure to retain or attract qualified executives could have an adverse effect on our ability to operate our business.

Efficient coal mining using modern techniques and equipment also requires skilled laborers in multiple disciplines such as electricians, equipment operators, mechanics, engineers and welders, among others. We have from time to time encountered shortages for these types of skilled labor and typically compete for such positions with other industries, including oil and gas. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially adversely affected. In the future, we may utilize a greater number of external contractors for portions of our operations. The costs of these contractors have historically been higher than that of our employed laborers. If our labor and contractor prices increase, or if we experience materially increased health and benefit costs with respect to our employees, our results of operations could be materially adversely affected.

Our work force could become unionized in the future, which could negatively impact the stability of our production and materially reduce our profitability.

All of our mines are operated by non-union employees. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union, and in the past, unions have conducted limited organizing

Table of Contents

activities in this regard. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could negatively impact the stability of our production and materially reduce our profitability. In addition, even if our managed operations remain non-union, our business may still be adversely affected by work stoppages at unionized companies or unionized transportation and service providers.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war may materially adversely affect our business and results of operations.

Terrorist attacks and threats, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could negatively impact our business. Furthermore, any such acts which directly affect our customers and their business may have negative consequences to our own operations. Strategic targets such as energy-related assets and transportation assets may be at greater risk of future terrorist attacks than other targets in the U.S. or in other countries. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business and results of operations, including from delays or losses in transportation, decreased sales of our coal or extended collections from customers that are unable to timely pay us in accordance with the terms of their supply agreement.

We face the risk of systems failures as well as cybersecurity risks, including hacking.

The computer systems and network infrastructure we and others use could be vulnerable to unforeseen problems. These problems may arise in both our internally developed systems and the systems of our third-party service providers. Our operations are dependent upon our ability to protect computer equipment against damage from fire, power loss or telecommunication failure. Any damage or failure that causes an interruption in our operations could adversely affect our business. In addition, our computer systems and network infrastructure present security risks, and could be susceptible to hacking.

Risks Related to Our Indebtedness and Liquidity

Our substantial indebtedness could adversely affect our results of operations and financial condition and prevent us from fulfilling our financial obligations.

At December 31, 2014, we had consolidated indebtedness of $509.0 million. We also have lease and royalty obligations related to our federal coal leases. Our outstanding indebtedness could have important consequences such as:

- limiting our ability to obtain additional financing to fund growth, such as mergers and acquisitions; working capital; capital expenditures; debt service requirements; LBA payments or other cash requirements;

- requiring much of our cash flow to be dedicated to interest obligations and making it unavailable for other purposes;

- with respect to any indebtedness under the revolving credit facility or other variable rate debt, exposing us to the risk of increased interest costs if the underlying interest rates rise on our variable rate debt;

- limiting our ability to invest operating cash flow in our business (including to obtain new LBAs or make capital expenditures) due to debt service requirements;

- causing us to need to sell assets and properties at an inopportune time;

- limiting our ability to compete effectively 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 LBAs and plant and equipment needed to conduct operations;

- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we operate and general economic and market conditions; and

- a downgrade in the credit rating of our indebtedness, which could increase the cost of further borrowings and negatively impact our available liquidity.

Table of Contents

We may incur substantially more debt in the future. If our indebtedness is further increased, the related risks that we now face, including those described above, could increase. Moreover, these risks also apply to certain of CPE Resources s domestic restricted subsidiaries that are guarantors of CPE Resources s indebtedness and apply to CPE Inc. directly as a guarantor of CPE Resources s indebtedness. In addition to the principal repayments on outstanding debt, we have other demands on our cash resources, including significant maintenance and other capital expenditures, including LBAs, and operating expenses. Our ability to pay our debt depends upon our operating performance. In particular, economic conditions could cause revenue to decline, and hamper our ability to repay 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, limit certain capital expenditures, including LBAs, or reduce spending or we may be required to issue equity. We may not be able to, at any given time, refinance our debt or sell assets and we may not be able to, at any given time, issue equity, in either case on acceptable terms or at all.

If we are unable to comply with the covenants or restrictions contained in our debt instruments, the lenders could declare all amounts outstanding under those instruments to be due and payable and foreclose on their collateral, which could materially adversely affect our financial condition and operations.

Our debt instruments include covenants that, among other things, restrict our ability to dispose of assets, incur additional indebtedness, pay dividends or make other restricted payments, create liens on assets, make investments, loans or advances, make acquisitions, engage in mergers or consolidations and engage in certain transactions with affiliates. The debt instruments also require compliance with various financial covenants. Because CPE Resources (which entered into the debt instruments) is our only direct operating subsidiary, complying with these restrictions and covenants may prevent us from taking actions that we believe would help us to grow our business. These restrictions could limit our ability to plan for or react to market conditions or meet extraordinary capital needs or otherwise restrict corporate activities.

A failure to comply with any of these restrictions or covenants could have serious consequences to our financial condition or result in a default under those debt instruments and under other agreements containing cross-default provisions. A default would permit lenders to accelerate the maturity of the debt under these debt instruments and to foreclose upon collateral securing the debt. Furthermore, an event of default or an acceleration under one of our debt instruments could also cause a cross-default or cross-acceleration of another debt instrument or contractual obligation, which would adversely impact our liquidity. Under these circumstances, we might not have sufficient funds or other resources to satisfy all of our obligations. We may not be granted waivers or amendments to these debt instruments if for any reason we are unable to comply with these debt instruments, and we may not be able to refinance our debt on terms acceptable to us, or at all.

Covenants under our revolving credit facility may limit the amount of funds available to us.

Our ability to borrow is subject to the terms and conditions of our revolving credit facility. The financial covenants are based on EBITDA for the preceding four fiscal quarters (which is defined in the credit agreement and is not the same as EBITDA or Adjusted EBITDA otherwise presented), requiring us to maintain defined minimum levels of interest coverage and providing for a limitation on our leverage ratio. Our earnings may not be sufficient to allow for the full availability on the revolving credit facility and the Accounts Receivable Securitization Facility (A/R Securitization Program). For example, the Credit Agreement requires us to maintain (a) a ratio of EBITDA to consolidated net cash interest expense equal to or greater than 1.50 to 1 (Interest Ratio), and (b) a ratio of senior secured funded debt less unrestricted cash and marketable securities (net secured debt) to EBITDA equal to or less than 4.00 to 1 (Leverage Ratio). Based on the Leverage Ratio, our aggregate available borrowing capacity under the revolving credit facility and the A/R Securitization Program was approximately $552.1 million at December 31, 2014. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Senior Secured Revolving Credit Facility.

Provisions in our debt instruments could discourage an acquisition of us by a third party.

Upon the occurrence of certain transactions constituting a change in control as defined in the indenture, holders of the senior notes have the right to require us to repurchase all outstanding notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. Furthermore, a change in control as defined in our credit facility is considered an event of default. These provisions could make it more difficult or more expensive for a third party to acquire us even where the acquisition could be beneficial to our stockholders.

Table of Contents

Other Risks Related to Our Corporate Structure and Common Stock

Our previous separation from Rio Tinto could subject us and our stockholders to any number of risks and uncertainties.

We entered into various agreements with Rio Tinto and its affiliates in connection with the IPO and separation from Rio Tinto. CPE Resources agreed to indemnify Rio Tinto for certain losses pursuant to these agreements. Because these agreements were entered into while we were part of Rio Tinto, some of the terms of these agreements are likely less favorable to us than similar agreements negotiated between unaffiliated third parties. Third parties may also seek to hold us responsible for liabilities of Rio Tinto that we did not assume in connection with the IPO and for which Rio Tinto agreed to indemnify us, including liabilities related to the Jacobs Ranch and Colowyo mines, as well as the uranium mining venture that we do not own. If those liabilities are significant and we are ultimately held liable for them, we may not be able to recover the full amount of our losses from Rio Tinto. Refer to the applicable exhibits listed in Item 15 of this Form 10-K for the complete terms and conditions of the principal outstanding agreements with Rio Tinto entered into in connection with our 2009 IPO.

CPE Inc. is a holding company with no direct operations of its own and depends on distributions from CPE Resources to meet its ongoing obligations.

CPE Inc. is a holding company with no direct operations of its own and has no independent ability to generate revenue. Consequently, its ability to obtain operating funds depends upon distributions from CPE Resources and payments under the management services agreement. Pursuant to its management services agreement, CPE Resources makes payments to CPE Inc. in the form of a management fee and cost reimbursements to fund CPE Inc. s day-to-day operating expenses, such as payroll for its officers. However, if CPE Resources cannot make the payments pursuant to the management services agreement, CPE Inc. may be unable to cover these expenses.

The distribution of cash flows by CPE Resources to CPE Inc. is subject to statutory restrictions under the Delaware Limited Liability Company Act and contractual restrictions under CPE Resources s debt instruments that may limit the ability of CPE Resources to make distributions. In addition, any distributions and payments of fees or costs are subject to CPE Resources s financial condition.

As the sole member of CPE Resources, CPE Inc. incurs income taxes on any net taxable income of CPE Resources. The debt instruments allow CPE Resources to distribute cash in amounts sufficient for CPE Inc. to pay its tax liabilities payable to any governmental entity. To the extent CPE Inc. needs funds for any other purpose, and CPE Resources is unable to provide such funds for any reason, it could have a material adverse effect on our business, financial condition, results of operations or prospects.

Our stock price has been volatile and could decline for a variety of reasons, resulting in a substantial loss on investment and negatively impacting our ability to raise equity capital in the future.

Significant price fluctuations in CPE Inc. s common stock could result from a variety of factors, including, among other things, actual or anticipated fluctuations in our operating results or financial condition, new laws or regulations or new interpretations of existing laws or regulations impacting our business, our customers businesses, or the coal transportation and logistics industry, sales of CPE Inc. s common stock by our stockholders or by us, a downgrade or cessation in coverage from one or more of our analysts, broad market fluctuations and general economic conditions and any other factors described in this Risk Factors section of this Form 10-K. For example, our stock price decreased from $18.08 on January 2, 2014 to $9.18 on December 31, 2014.

A decline in the trading price of CPE Inc. s common stock due to any future sales of stock or the issuance or exercise of equity-based awards under our Long Term Incentive Plan or sales to cover taxes owed upon vesting of awards, or due to other factors might impede our ability to raise capital through the issuance of additional shares of CPE Inc. s common stock or other equity securities and may cause you to lose part or all of your investment in shares of our common stock.

Table of Contents

Anti-takeover provisions in our charter documents and other aspects of our structure may discourage, delay or prevent a change in control of our company and may adversely affect the trading price of CPE Inc. s common stock.

Certain provisions in CPE Inc. s amended and restated certificate of incorporation and amended and restated bylaws and other aspects of our structure may discourage, delay or prevent a change in our management or a change in control over us that stockholders may consider favorable. Among other things, CPE Inc. s amended and restated certificate of incorporation and amended and restated bylaws:

- provide for a classified Board of Directors, which may delay the ability of our stockholders to change the membership of a majority of our Board of Directors;
- authorize the issuance of blank check preferred stock that could be issued by our Board of Directors to thwart a takeover attempt;
- do not provide for cumulative voting;
- provide that vacancies on the Board of Directors, including newly created directorships, may be filled only by a majority vote of directors then in office;
- limit the calling of special meetings of stockholders;
- provide that stockholders may not act by written consent;
- provide that our directors may be removed only for cause;
- require supermajority voting to effect certain amendments to our certificate of incorporation and our bylaws; and
- require stockholders to provide advance notice of new business proposals and director nominations under specific procedures.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

See Item 1 Business Mining Operations for specific information about our mining operations.

Coal Reserves

As of December 31, 2014, we controlled approximately 1.1 billion tons of proven and probable coal reserves. All of our proven and probable reserves are classified as thermal coal.

The following table summarizes the tonnage of our coal reserves that is classified as proven or probable, and assigned, as well as our property interest, as of December 31, 2014:

Mine	Proven Preserves	Probable Reserves	Total Proven & Probable Reserves	Assigned Reserves	Reserves Owned	Reserves Leased
		(nearest million, in tons)		(%)	(nearest million, in tons)	
Antelope	435	146	581	100		581
Cordero Rojo	217	50	267	100	55	212
Spring Creek	249	25	274	100		274
Total (1)	901	221	1,122		55	1,067

(1) Totals reflect rounding.

Table of Contents

The following table provides the quality (average sulfur content and average Btu per pound) of our coal reserves as of December 31, 2014:

Mine	Total Proven & Probable Reserves (nearest million, in tons)	Average Btu per lb (1)	Average Sulfur Content (%)	Average Sulfur Content (lbs SO2/ mmBtu)
Antelope	581	8,875	0.22	0.50
Cordero Rojo	267	8,425	0.29	0.69
Spring Creek	274	9,350	0.34	0.73
Total (2)	1,122			

(1) Average Btu per pound includes weight of moisture in the coal on an as-sold basis.

(2) Totals reflect rounding.

We also control certain coal deposits that are contiguous to or near our primary reserve bases. The tons in these deposits are classified as non-reserve coal deposits and are not included in our reported reserves. These non-reserve coal deposits include:

- 8 million tons near our Antelope Mine;
- 148 million tons near our Cordero Rojo Mine;
- 3 million tons near our Spring Creek Mine; and
- 287 million tons at the Youngs Creek project.

Non-reserve coal deposits are not reserves under SEC Industry Guide 7. Estimates of non-reserve coal deposits are subject to further exploration and development, are more speculative and may not be converted to future reserves of the company.

Our reserve and non-reserve coal deposit estimates as of December 31, 2014 were prepared by our staff of geologists and engineers, who have extensive experience in PRB coal. These individuals are responsible for collecting and analyzing geologic data within and adjacent to leases controlled by us. Our Manager Geological Services is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has a Bachelor of Science degree in Geology and Master of Science degree in Engineering Geology and over 35 years of industry experience with positions of increasing responsibility in mining geology, reserve determination, project evaluations, and technical management at CPE Inc. The Manager Geological Services reports directly to our Senior Vice President, Technical Services. An external review of our reserves and non-reserve coal deposit estimates is performed every two years. The most recent review was performed for the year ended December 31, 2014 and was completed in January 2015 by John T. Boyd Company, mining and geological consultants. The results verified our reserve and non-reserve coal deposit estimates for the year ended December 31, 2014.

Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data. All of our reserves are assigned, associated with our active coal properties, and incorporated in detailed mine plans. Estimates of our reserves are based on more than 6,000 drill holes. Our proven reserves have a typical drill hole spacing of 1,500 feet or less, and our probable reserves have a typical drill hole spacing of 2,500 feet or less.

Along with the geological data we assemble for our coal reserve estimates, our staff of geologists and engineers also analyzes the economic data such as cost of production, projected sales price and other data concerning permitting and advances in mining technology. Various factors and assumptions are utilized in estimating coal reserves, including assumptions concerning future coal prices and operating costs. These estimates are periodically updated to reflect past coal production and other geologic or 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.

Table of Contents

Reserve Acquisition Process

Since our inception, we have focused on growth through the acquisition of proven and probable coal reserves and non-reserve coal deposits. Historically, this was accomplished through the federal competitive leasing process, known as the LBA process. For example, in 2011 we acquired 383 million tons of proven and probable coal reserves in two federal coal leases for our Antelope Mine.

We acquire a large portion of our coal through the LBA process, and as a result, most of our coal is held under federal leases. Under this process, before a mining company can obtain a new federal coal lease, the company must nominate a coal tract for lease and then win the lease through a competitive bidding process. The LBA process can last anywhere from two to five years or more from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves and begins the process to permit the coal for mining, which generally takes another two to five years. Third-party legal challenges, such as legal challenges filed against the BLM and the Secretary of the Interior by environmental groups with respect to the LBA process in the PRB may result in delays and other adverse impacts on the LBA process.

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 whether 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.

The BLM also allows for small tracts of coal to be acquired through the LBM leasing process. An LBM is a non-competitive leasing process and is used in circumstances where a lessee is seeking to modify an existing federal coal lease by adding less than 960 acres in a configuration that is deemed non-competitive to other coal operators. For example, in December 2012, we applied for two separate LBMs with the BLM: one at the Spring Creek Mine and one at the Antelope Mine. As of December 31, 2014, an environmental assessment was underway for the Antelope LBM and the Spring Creek application was being processed by the BLM.

If the BLM determines to continue the application, the company that submitted the application will pay for a BLM-directed environmental analysis or an EIS to be completed. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other government 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 EIS 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 payer. 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 EIS, and the winning bidder will bear those costs. Coal awarded through the LBA process and subject to federal leases is administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. Once the BLM has issued a lease, the company must next complete the permitting process before it can mine the coal. See Item 1 Business Environmental and Other Regulatory Matters Mining Permits and Approvals.

The federal coal leasing process is designed to be a public process, giving stakeholders and other interested parties opportunities to comment on the BLM s proposed and final actions and allow third-party comments. Because of this, third parties, including NGOs, can challenge the BLM s actions, which may delay the leasing process. If these challenges prove

Table of Contents

successful or are litigated for a prolonged period of time, a coal company s ability to bid on or acquire a new coal lease could be significantly delayed, or could cause the BLM to not offer a lease for bid at all. For example, environmental organizations filed legal challenges against the BLM s findings on the final EIS and other matters associated with the West Antelope II LBA, which was nominated by our Antelope Mine. Though these challenges were unsuccessful and the plaintiffs abandoned their efforts for appeal, these types of challenges create some uncertainty with respect to the timing of future LBA bids and lease acquisitions and may ultimately delay the leasing process or prevent mining operations. Even after a lease has been issued and a successful bidder has paid installment money to the BLM, legal challenges may still seek to delay or prevent mining operations. It is possible that subsequent EISs for other mines in the PRB currently underway but not yet final could be similarly challenged. There also exists the possibility of similar challenges to the permitting and licensing process, which is also a public process designed to allow public comments.

Each of our federal coal leases has an initial term of 20 years, renewable for subsequent 10-year periods and for so long thereafter as coal is produced in commercial quantities. The lease requires diligent development within the first 10 years of the lease award with a required coal extraction of 1% 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 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. We currently have an LMU for our Antelope Mine. We pay to the federal government an annual rent of $3.00 per acre and production royalties of 12.5% of gross revenue on surface mined coal. The federal government remits approximately 50% of the production royalty payments to the state after deducting administrative expenses. Some of our mines are also subject to coal leases with the states of Montana or Wyoming, as applicable, 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.

Most of the coal we lease from the U.S. comes from split estate lands in which one party, such as the federal government, owns the coal and a private party owns the surface. In order to mine the coal we acquire, we must acquire rights to mine from certain owners of the surface lands overlying the coal. Certain federal regulations provide a specific class of surface owners, QSOs, with the ability to prohibit the BLM from leasing its coal. For example, in connection with an LBA tract that we previously nominated for our Cordero Rojo Mine, the BLM indicated that certain surface owners satisfied the regulatory definition of QSO. If the land overlying a coal tract is owned by a QSO, federal laws prohibit us from leasing the coal tract without first securing surface rights to the land, or purchasing the surface rights from the QSO, which would allow us to conduct our mining operations. Furthermore, the state permitting process requires us to demonstrate surface owner consent for split estate lands before the state will issue a permit to mine coal. This consent is separate from the QSO consent required before leasing federal coal. This right of QSOs and certain other surface owners allows them to exercise significant influence over negotiations and prices to acquire surface rights and can delay the federal coal lease or permitting processes or ultimately prevent the acquisition of the federal coal lease or permit over that land entirely. There are QSOs that own land adjacent to or near our existing mines that may be attractive acquisition candidates for us. Typically, we seek to purchase the land overlying our coal or enter into option agreements granting us an option to purchase the land upon acquiring a federal coal lease. We own substantially all of the land over our reserves. We may not own or control the land over our non-reserve coal deposits, which would be required before these non-reserve coal deposits could be classified as reserves and mined.

Most of the coal we have acquired from private third parties is in the form of coal leases obtained through private negotiations with one or more third parties. These leases generally include, among other terms and conditions, a set term of years with the right to renew the lease for a stated period and royalties to be paid to the lessor as a percentage of the sales price. These leases may require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments, and a minimum production of coal from the leased areas in order to hold the leases by active production. We believe that the term of years will allow the recoverable reserve to be fully extracted in accordance with our projected mine plan. Consistent with industry practice, we conduct only limited investigations of title to our coal properties prior to leasing. Title to properties leased from private third parties is not usually fully verified until we make a commitment to develop a property, which may not occur until we have obtained the necessary permits and completed exploration of the property.

We acquired significant coal deposits when we completed the acquisition of the Youngs Creek project, a non-operating mine in Northeast Wyoming in the Northern PRB, whereby we acquired 287 million tons of non-reserve coal deposits along with significant related surface assets. We also announced in 2013 that we signed an option agreement and a corresponding exploration agreement with the Crow Tribe of Indians for the exploration and potential development of significant coal resources on the Crow Indian Reservation in southeast Montana in the Northern PRB region. We intend to

Table of Contents

continue to seek opportunities to acquire additional coal through the federal leasing process as well as through private transactions with third parties or sovereign nations such as the Crow Tribe of Indians.

Office Space

Our corporate headquarters is located in Gillette, Wyoming, where we own approximately 31,000 square feet of office space. In addition, we lease approximately 7,500 square feet of additional office space in Gillette, Wyoming, under an annual lease expiring on April 14, 2016, and we lease approximately 28,100 square feet of office space in Broomfield, Colorado under a lease that expires in February 2021. As of December 31, 2014, all of our long-lived assets were located in the U.S. See Note 24 of Notes to Consolidated Financial Statements in Item 8.

Item 3. ***Legal Proceedings.***

Litigation

WildEarth Guardians and Northern Plains Resource Council s Regulatory Challenge to OSM s Approval Process for Mine Plans

Background On February 27, 2013, WildEarth Guardians (WildEarth) filed a complaint in the United States District Court for the District of Colorado (Colorado District Court) challenging the federal Office of Surface Mining s (OSM) approvals of mine plans for seven different coal mines located in four different states. The challenged approvals included two that were issued to subsidiaries of Cloud Peak Energy: one for the Cordero Rojo Mine in Wyoming and one for the Spring Creek Mine in Montana.

On February 7, 2014, the Colorado District Court severed the claims in WildEarth s complaint and transferred all the claims pertaining to non-Colorado mines to the federal district courts for the states in which the mines were located. Pursuant to this order, the challenge to Cordero Rojo s mine plan approval (along with challenges to two other OSM approvals) was transferred to the United States District Court in Wyoming (Wyoming District Court) and the challenge to Spring Creek s mine plan approval was transferred to the United States District Court for the District of Montana (Montana District Court). On February 14, 2014, WildEarth voluntarily dismissed the case pending in the Wyoming District Court, thereby concluding its challenge to OSM s approval of the Cordero mine plan. WildEarth has continued to pursue its challenges to mine plan approvals pending in district courts in Colorado, New Mexico, and Montana.

On March 14, 2014, WildEarth amended its complaint in the Montana District Court to reflect the transfer order from the Colorado District Court. WildEarth has asked the Montana District Court to vacate OSM s 2012 approval of the Spring Creek mine plan and enjoin mining operations at the Spring Creek Mine until OSM undertakes additional environmental analysis and related public process requested by WildEarth.

On August 14, 2014, Northern Plains Resource Council and the Western Organization of Resource Councils (collectively Northern Plains) filed a complaint in the Montana District Court challenging the same OSM approval of Spring Creek s mine plan. Northern Plains, like WildEarth, requested that the Montana District Court vacate OSM s 2012 approval of the Spring Creek mine plan and enjoin mining operations at the Spring Creek Mine until OSM undertakes the additional analysis requested by Northern Plains.

Intervention by Cloud Peak Energy and Others By orders dated May 30, 2014, May 9, 2014, and April 28, 2014, the Montana District Court granted intervention to the State of Montana, the National Mining Association, and Spring Creek Coal LLC, a 100% owned subsidiary of Cloud Peak Energy, respectively. Each of these parties intervened on the side of OSM.

Current Schedule On October 28, 2014, the Court consolidated the WildEarth and Northern Plains cases and set a briefing schedule for resolution of all of WildEarth s and Northern Plains claims through motions for summary judgment. Plaintiffs filed their opening briefs on December 8, 2014, and briefing by all parties is scheduled to be completed by April 28, 2015. Cloud Peak Energy believes WildEarth s challenge and the related Northern Plains challenge against OSM are without merit.

Montana Environmental Information Center and Sierra Club Regulatory Challenge to Montana DEQ s Coal Permit Program

Background On April 17, 2012, the Montana Environmental Information Center and the Sierra Club (collectively, MEIC) filed a complaint in the Montana District Court against the Director of the Montana Department of Environmental Quality (DEQ Director) alleging that the DEQ Director violated his nondiscretionary duties under SMCRA by approving state mine permits without establishing numeric water quality standards as part of MT DEQ s cumulative hydrologic impact

Table of Contents

assessments (CHIAs) for coal mines. MEIC asked the Montana District Court to issue an order directing the DEQ Director to perform CHIAs in a manner requested by plaintiff organizations, and to enjoin the DEQ Director s approval of new mine permit applications until this analysis is completed.

Intervention by Cloud Peak Energy and Others On August 3, 2012, the Montana District Court granted the intervention motion of a number of other companies that own coal mines and/or coal reserves, the Crow Tribe, a labor union representing mine workers, and Spring Creek Coal LLC, a 100% owned subsidiary of Cloud Peak Energy. All these parties jointly intervened on the side of the DEQ Director.

District Court Rejection of Challenge and MEIC Appeal On January 22, 2013, the Montana District Court dismissed MEIC s challenge on the ground that the action was barred by Montana s 11th Amendment Sovereign Immunity. The Montana District Court also held that the DEQ Director s CHIAs were discretionary actions and therefore not subject to SMCRA s citizen suit provision, and alternatively, that MEIC s claims were not ripe for judicial review. On February 20, 2013, MEIC appealed to the United States Court of Appeals for the Ninth Circuit and asked the Ninth Circuit to reverse the judgment of the Montana District Court dismissing MEIC s case. Spring Creek and the other intervenors in the Montana District Court intervened in this appeal as respondents on the side of the DEQ Director.

Court of Appeals Rejection of Challenge On September 11, 2014, the Ninth Circuit Court of Appeals issued a unanimous decision affirming the Montana District Court s dismissal of MEIC s complaint. MEIC declined to seek further review in the Ninth Circuit and the Court s mandate was issued on October 6, 2014. MEIC did not petition the Supreme Court for review of the Ninth Circuit s decision and the appeal is now concluded.

Administrative Appeals of BLM s Approval of the Potential West Antelope II South Lease Modification

Background On September 5, 2014, WildEarth filed an appeal with the Interior Board of Land Appeals (IBLA) challenging the Bureau of Land Management s (BLM) August 15, 2014 decision to approve Antelope Coal LLC s proposed modification of Antelope Coal s West Antelope II South Lease. Antelope Coal is a 100% owned subsidiary of Cloud Peak Energy. On September 12, 2014, Powder River Basin Resource Council and Sierra Club (collectively PRBRC) filed an appeal with the IBLA challenging this same BLM decision. The BLM decision that is the subject of both appeals approves the proposed amendment of Antelope Coal s West Antelope II South Lease. If the lease modification is entered into, it would add approximately 15.8 million tons of coal underlying nearly 857 surface acres. WildEarth and PRBRC have asked the IBLA to vacate the proposed WAII South lease modification and direct BLM to prepare additional environmental analysis on the impacts of the lease modification.

Intervention by Cloud Peak Energy and State of Wyoming On September 24, 2014 and October 6, 2014, Antelope Coal and the State of Wyoming, respectively, moved to intervene in the WildEarth and PRBRC appeals as respondents to defend BLM s lease modification decision. The IBLA granted these intervention motions.

Current Schedule. WildEarth filed its Statement of Reasons (opening brief) on October 6, 2014, and PRBRC filed its Statement of Reasons on October 10, 2014. BLM filed its Answer (opposition brief) on January 12, 2015 and moved for the two appeals to be consolidated. Antelope Coal and the State of Wyoming filed their respective Answers on January 20, 2015. Briefing is expected to be completed in both appeals in February 2015. Cloud Peak Energy believes the WildEarth and PRBRC appeals challenging BLM s West Antelope II South lease modification decision are without merit.

Other Legal Proceedings

We are involved in other legal proceedings arising in the ordinary course of business and may become involved in additional proceedings from time to time. We believe that there are no other legal proceedings pending that are likely to have a material adverse effect on our consolidated financial condition, results of operations or cash flows. Nevertheless, we cannot predict the impact of future developments affecting our claims and lawsuits, and any resolution of a claim or lawsuit or an accrual within a particular fiscal period may adversely impact our results of operations for that period. In addition to claims and lawsuits against us, our LBAs, LBMs, permits, and other industry regulatory processes and approvals, including those applicable to the utility and coal logistics and transportation industries, may also be subject to legal challenges that could adversely impact our mining operations and results.

Item 4. ***Mine Safety Disclosures***

The information 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 95.1 to this Form 10-K.

Table of Contents

PART II

Item 5. ***Market for Registrant s Common Equity and Related Stockholder Matters.***

Our common stock, $0.01 par value, is traded on the New York Stock Exchange (NYSE) under the symbol CLD . The following table sets forth the intraday high and low sales prices of our common stock, as reported by the NYSE, for each of the periods listed.

	High	Low
Fiscal Year 2014		
Fourth Quarter 2014	$ 13.96	$ 8.91
Third Quarter 2014	$ 18.55	$ 12.10
Second Quarter 2014	$ 22.43	$ 17.74
First Quarter 2014	$ 21.28	$ 16.27
Fiscal Year 2013		
Fourth Quarter 2013	$ 18.58	$ 14.38
Third Quarter 2013	$ 17.43	$ 14.25
Second Quarter 2013	$ 20.30	$ 16.17
First Quarter 2013	$ 19.99	$ 15.44

The last reported sale price of our common stock on the NYSE on December 31, 2014 was $9.18 per share. As of the close of business on January 30, 2015, there were 183 holders of record of our common stock.

Dividend Policy

We have not historically paid, and we do not anticipate that we will pay in the near term, cash dividends on CPE Inc. s common stock. Any determination to pay dividends to holders of CPE Inc. s common stock in the future will be at the discretion of our Board of Directors and will depend on many factors, including our financial condition; results of operations; general business conditions; contractual restrictions, including those under our debt instruments; capital requirements; business prospects; restrictions on the payment of dividends under Delaware Law; and any other factors our Board of Directors deems relevant. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Senior Notes and Senior Secured Revolving Credit Facility.

Stock Performance Graph

The following performance graph compares the cumulative total return on CPE Inc. s common stock with the cumulative total return of the following indices: (i) the Standard & Poor s (S&P) MidCap 400 stock index and (ii) the Custom Composite Index. The Custom Composite Index is comprised of the peer group that is associated with our performance-based share units issued under our Long Term Incentive Plan. In 2013, this group was comprised of Alliance Resource Partners LP, Alpha Natural Resources, Inc., Arch Coal, Inc., Cabot Oil & Gas Corporation, CONSOL Energy Inc., EQT Corporation, Forest Oil Corporation, James River Coal Company, Newfield Exploration Co., Noble Energy, Inc., Oxford Resource Partners, L.P., Peabody Energy Corp., Penn Virginia Corporation, Rhino Resource Partners LP, SandRidge Energy, Inc., SM Energy Company, SunCoke Energy Inc., Walter Energy, Inc., Westmoreland Coal Co., and Whiting Petroleum Corp. Each year the compensation committee of our Board of Directors seeks to refine this group, if deemed appropriate in the judgment of the compensation committee, to be the most representative comparable companies for purposes of our performance-based share units. There were no changes in 2014 other than to remove Berry Petroleum as it was acquired and is no longer traded on the NYSE.

The graph assumes that you invested $100 in CPE Inc. s common stock and in each index at the closing price on December 31, 2009, that all dividends were reinvested and that you continued to hold your investment through December 31, 2014.

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

Table of Contents

Company/ Market/ Peer Group		2009		2010		2011		2012		2013		2014
CPE Inc.	$	100.00	$	159.55	$	132.69	$	132.76	$	123.63	$	63.05
S&P MidCap 400 Index	$	100.00	$	126.64	$	124.45	$	146.70	$	195.84	$	214.97
Custom Composite	$	100.00	$	131.22	$	102.69	$	92.51	$	115.36	$	81.62

In accordance with SEC rules, the information contained in the Stock Performance Graph above shall not be deemed to be soliciting material, or to be filed with the SEC or subject to the SEC s Regulation 14A or 14C, other than as provided under Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended, except to the extent that we specifically request that the information be treated as soliciting material or specifically incorporate it by reference into a document filed under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Issuer Purchases of Equity Securities

The table below represents information pursuant to Item 703 of Regulation S-K regarding all share repurchases for the three-month period ended December 31, 2014:

	Total Number of Shares Purchased (1)		Average Price per Share
October 1 through October 31, 2014		$	
November 1 through November 30, 2014			
December 1 through December 31, 2014	9		9.90
Total	9	$	9.90

(1) Represents shares withheld to cover withholding taxes upon the vesting of restricted stock.

Item 6. ***Selected Financial Data.***

The following tables set forth our selected consolidated financial and other data on a historical basis. The information below should be read in conjunction with Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8 Financial Statements and Supplementary Data included elsewhere in this report.

We have derived the historical consolidated financial data as of December 31, 2014 and 2013 and for each of the three years in the period ended December 31, 2014 from our audited consolidated financial statements included in Item 8 of this report. We have derived the historical consolidated balance sheet data as of December 31, 2012, 2011 and 2010 and the historical consolidated statements of operations data for the years ended December 31, 2011 and 2010 from our audited consolidated financial statements not included in this report.

Table of Contents

Selected Consolidated Financial and Other Data

	Year Ended December 31, 2014	2013	2012	2011	2010
	(in millions, except per share amounts)				
Statement of Operations Data					
Revenue	$ 1,324.0	$ 1,396.1	$ 1,516.8	$ 1,553.7	$ 1,370.8
Operating income	131.8	112.4	241.9	250.5	211.9
Net income	79.0	52.0	173.7	189.8	117.2
Net income attributable to controlling interest(1)	79.0	52.0	173.7	189.8	33.7
Earnings per share attributable to controlling interest basic(1)	$ 1.30	$ 0.86	$ 2.89	$ 3.16	$ 1.06
Earnings per share attributable to controlling interest diluted(1)	$ 1.29	$ 0.85	$ 2.85	$ 3.13	$ 1.06

	December 31, 2014	2013	2012	2011	2010
	(in millions)				
Balance Sheet Data					
Cash and cash equivalents	$ 168.7	$ 231.6	$ 197.7	$ 404.2	$ 340.1
Investments in marketable securities		80.7	80.3	75.2	
Property, plant and equipment, net	1,589.1	1,654.0	1,678.3	1,350.1	1,008.3
Total assets	2,159.9	2,357.4	2,351.3	2,319.3	1,915.1
Long-term debt	498.5	597.0	596.5	596.1	595.7
Federal coal leases obligations	64.0	122.9	186.1	288.3	118.3
Total liabilities	1,072.1	1,355.4	1,420.3	1,568.9	1,383.9
Total equity	1,087.8	1,002.0	931.0	750.4	531.2

	Year Ended December 31, 2014	2013	2012	2011	2010
	(in millions)				
Other Data					
Adjusted EBITDA(4)	$ 201.9	$ 218.6	$ 338.8	$ 351.7	$ 322.7
Adjusted EPS(4)	$ 0.19	$ 0.73	$ 2.15	$ 2.47	$ 1.74
Asian export tons Logistics and Related Activities	4.0	4.7	4.4	4.7	3.3
Tons sold Owned and Operated Mines(2)	85.9	86.0	90.6	95.6	93.7
Tons sold Decker Mine(3)	1.1	1.5	1.4	1.5	1.5
Tons purchased and resold	0.1	1.5	0.9	1.6	1.7
Total tons sold	87.1	89.1	93.0	98.7	96.9
Ratio of earnings to fixed charges - see Exhibit 12.1	2.6	1.6	3.5	3.0	2.7

(1) For the period following the IPO up to the Secondary Offering, income or loss attributable to controlling interest reflects our interest in CPE Resources and its subsidiaries.

(2) Inclusive of intersegment sales.

(3) Based on our 50% non-operating interest, which was sold on September 12, 2014.

(4) EBITDA, Adjusted EBITDA and Adjusted EPS are intended to provide additional information only and do not have any standard meaning prescribed by generally accepted accounting principles in the U.S. (U.S. GAAP). A quantitative reconciliation of Adjusted EBITDA to net income (loss) and Adjusted EPS to EPS (as defined below) is found in the tables below.

EBITDA represents net income (loss) before: (1) interest income (expense) net, (2) income tax provision, (3) depreciation and depletion, and (4) amortization. Adjusted EBITDA represents EBITDA as further adjusted for accretion, which represents non-cash increases in asset retirement obligation liabilities resulting from the passage of time, and specifically identified items that management believes do not directly reflect our core operations. For the periods presented herein, the specifically identified items are: (1) adjustments to exclude the updates to the tax agreement liability, including tax impacts of the IPO and Secondary Offering and the termination of the TRA in August 2014, (2) adjustments for derivative financial instruments, excluding fair value mark-to-market gains or losses and including cash amounts received or paid, (3) adjustments to exclude the gain from the sale of our 50% non-operating interest in the Decker Mine, and (4) adjustments to exclude a significant broker contract that expired

Table of Contents

in the first quarter of 2010. We enter into certain derivative financial instruments such as put options that require the payment of premiums at contract inception. The reduction in the premium value over time is reflected in the mark-to-market gains or losses. Our calculation of Adjusted EBITDA does not include premiums paid for derivative financial instruments; either at contract inception, as these payments pertain to future settlement periods, or in the period of contract settlement, as the payment occurred in a preceding period.

Adjusted EPS represents diluted earnings (loss) per common share attributable to controlling interest (EPS) adjusted to exclude (i) the estimated per share impact of the same specifically identified non-core items used to calculate Adjusted EBITDA as described above, and (ii) the cash and non-cash interest expense associated with the early retirement of debt and refinancing transactions. All items are adjusted at the statutory tax rate of approximately 37%.

Adjusted EBITDA is an additional tool intended to assist our management in comparing our performance on a consistent basis for purposes of business decision making by removing the impact of certain items that management believes do not directly reflect our core operations. Adjusted EBITDA is a metric intended to assist management in evaluating operating performance, comparing performance across periods, planning and forecasting future business operations and helping determine levels of operating and capital investments. Period-to-period comparisons of Adjusted EBITDA are intended to help our management identify and assess additional trends potentially impacting our company that may not be shown solely by period-to-period comparisons of net income (loss). Our chief operating decision maker uses Adjusted EBITDA as a measure of segment performance. Consolidated Adjusted EBITDA is also used as part of our incentive compensation program for our executive officers and others.

We believe Adjusted EBITDA and Adjusted EPS are also useful to investors, analysts and other external users of our consolidated financial statements in evaluating our operating performance from period to period and comparing our performance to similar operating results of other relevant companies. Adjusted EBITDA allows investors to measure a company s operating performance without regard to items such as interest expense, taxes, depreciation and depletion, amortization and accretion and other specifically identified items that are not considered to directly reflect our core operations. Similarly, we believe our use of Adjusted EPS provides an appropriate measure to use in assessing our performance across periods given that this measure provides an adjustment for certain specifically identified significant items that are not considered to directly reflect our core operations, the magnitude of which may vary significantly from period to period and, thereby, have a disproportionate effect on the earnings per share reported for a given period.

Our management recognizes that using Adjusted EBITDA and Adjusted EPS as performance measures has inherent limitations as compared to net income (loss), EPS, or other U.S. GAAP financial measures, as these non-GAAP measures exclude certain items, including items that are recurring in nature, which may be meaningful to investors. Adjusted EBITDA excludes interest expense and interest income; however, as we have historically borrowed money in order to finance transactions and operations and have invested available cash to generate interest income, interest expense and interest income are elements of our cost structure and influence our ability to generate revenue and returns for stockholders. Adjusted EBITDA excludes depreciation and depletion and amortization; however, as we use capital and intangible assets to generate revenue, depreciation, depletion and amortization are necessary elements of our costs and ability to generate revenue. Adjusted EBITDA also excludes accretion expense; however, as we are legally obligated to pay for costs associated with the reclamation and closure of our mine sites, the periodic accretion expense relating to these reclamation costs is a necessary element of our costs and ability to generate revenue. Adjusted EBITDA excludes income taxes; however, as we are organized as a corporation, the payment of taxes is a necessary element of our operations. Adjusted EBITDA and Adjusted EPS exclude the tax impacts of the IPO and Secondary Offering; however, this represented our current estimate of payments on the tax agreement liability that we were required to make to Rio Tinto prior to the August 2014 termination of the TRA and changes to the realizability of our deferred tax assets based on changes in our estimated future taxable income. Adjusted EBITDA and Adjusted EPS exclude fair value mark-to-market gains or losses for derivative financial instruments and premiums paid at contract inception; however, Adjusted EBITDA and Adjusted EPS include cash amounts received or paid upon contract settlement on derivative financial instruments. Adjusted EBITDA and Adjusted EPS exclude income statement amounts attributable to our significant broker contract that expired in the first quarter of 2010; however, this historically represented a positive contribution to our operating results. Adjusted EBITDA and Adjusted EPS exclude the gain from the sale of the Decker Mine; however, the release of the reclamation and other liabilities is a significant benefit to us. Finally, Adjusted EPS excludes the cash and non-cash interest expense associated with the early retirement of debt and refinancing transactions; however, as we pay for costs associated with financing transactions, the related interest expense is a necessary element of our costs.

Table of Contents

As a result of these exclusions, Adjusted EBITDA and Adjusted EPS should not be considered in isolation and do not purport to be alternatives to net income (loss), EPS or other U.S. GAAP financial measures as a measure of our operating performance.

When using Adjusted EBITDA as a performance measure, management intends to compensate for these limitations by comparing it to net income (loss) in each period to allow for the comparison of the performance of the underlying core operations with the overall performance of the company on a full-cost, after-tax basis. Using Adjusted EBITDA and net income (loss) to evaluate the business assists management and investors in (a) assessing our relative performance against our competitors and (b) ultimately monitoring our capacity to generate returns for stockholders.

Because not all companies use identical calculations, our presentations of Adjusted EBITDA and Adjusted EPS may not be comparable to other similarly titled measures of other companies. Moreover, our presentation of Adjusted EBITDA is different than EBITDA as defined in our debt financing agreements.

A quantitative reconciliation for each of the periods presented of net income (loss) to Adjusted EBITDA and EPS to Adjusted EPS is as follows:

	Year Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
			(in millions)		
Net income	$ 79.0	$ 52.0	$ 173.7	$ 189.8	$ 117.2
Interest income	(0.3)	(0.4)	(1.1)	(0.6)	(0.6)
Interest expense	77.2	41.7	36.3	33.9	46.9
Income tax expense	34.9	11.6	62.6	11.4	32.0
Depreciation and depletion	112.0	100.5	94.6	87.1	100.0
Amortization					3.2
EBITDA	302.8	205.3	366.1	321.6	298.8
Accretion	15.1	15.3	13.2	12.5	12.5
Tax agreement expense (benefit)(1)	(58.6)	10.5	(29.0)	19.9	19.7
Derivative financial instruments:					
Exclusion of fair value mark-to-market losses (gains)(2)	(7.8)	(25.6)	(22.8)	(2.3)	
Inclusion of cash amounts received (paid)(3)(4)	24.7	13.0	11.2		
Total derivative financial instruments	16.9	(12.6)	(11.5)	(2.3)	
Gain on sale of Decker Mine interest	(74.3)				
Expired significant broker contract					(8.2)
Adjusted EBITDA	$ 201.9	$ 218.6	$ 338.8	$ 351.7	$ 322.7

(1) Changes to related deferred taxes are included in income tax expense.

(2) Fair value mark-to-market (gains) losses reflected on the statement of operations.

(3) Cash amounts received and paid reflected within operating cash flows.

	$ 4.0	$	$	$	$

(4) Excludes premiums paid at contract inception during the period

See Note 6 of Notes to Consolidated Financial Statements in Item 8 for a discussion related to the fair value of derivative financial instruments. There were no derivative financial instruments for the year ended December 31, 2010.

Table of Contents

A reconciliation of diluted earnings (loss) per common share attributable to controlling interest, as applicable, to Adjusted EPS for the periods presented is as follows:

	Year Ended December 31, 2014	2013	2012	2011	2010
Diluted earnings per common share attributable to controlling interest	$ 1.29	$ 0.85	$ 2.85	$ 3.13	$ 1.06
Tax agreement expense (benefit) including tax impacts of IPO and Secondary Offering	(0.73)	0.01	(0.58)	(0.63)	0.78
Derivative financial instruments:					
Exclusion of fair value mark-to-market losses (gains)	(0.08)	(0.27)	(0.24)	(0.02)	
Inclusion of cash amounts received(1)	0.25	0.14	0.12		
Total derivative financial instruments	0.17	(0.13)	(0.12)	(0.02)	
Refinancing transaction:					
Exclusion of cash interest for early retirement of debt	0.14				
Exclusion of non-cash interest for deferred finance fee write-off	0.08				
Total refinancing transaction	0.22				
Gain on sale of Decker Mine interest	(0.76)				
Expired significant broker contract					(0.10)
Adjusted EPS	$ 0.19	$ 0.73	$ 2.15	$ 2.47	$ 1.74
Weighted-average shares outstanding (in millions)	61.3	61.2	60.9	60.6	31.9

(1) Excludes the per share impact of premiums paid at contract inception during the period	$ 0.04	$	$	$	$

Due to the tabular presentation of rounded amounts, certain tables reflect insignificant rounding differences.

Table of Contents

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

Unless the context indicates otherwise, the terms Cloud Peak Energy, the Company, we, us, and our refer to Cloud Peak Energy Inc. and its subsidiaries.

This Item 7 may contain forward-looking statements that involve substantial risks and uncertainties. When considering these forward-looking statements you should keep in mind the cautionary statements in this report and our other SEC filings. Please see Cautionary Notice Regarding Forward-Looking Statements and Item 1A Risk Factors elsewhere in this document.

This Item 7 is intended to help the reader understand our results of operations and financial condition. This discussion should be read in conjunction with our consolidated financial statements in Item 8.

Overview

We are one of the largest producers of coal in the U.S. and the PRB, based on our 2014 coal sales. We operate some of the safest mines in the coal industry. According to the most current MSHA data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies.

We currently operate solely in the PRB, the lowest cost region of the major coal producing regions in the U.S., where we operate three 100% owned surface coal mines, the Antelope Mine, the Cordero Rojo Mine and the Spring Creek Mine. We also have two major development projects, the Youngs Creek project and the Crow project. On September 12, 2014, we completed the sale of our 50% non-operating interest in the Decker Mine to an affiliate of Ambre Energy. For further information regarding this transaction, please see Note 4 of Notes to Consolidated Financial Statements in Item 8.

Our Antelope Mine and Cordero Rojo Mine are located in Wyoming and our Spring Creek Mine is located in Montana. Our mines produce subbituminous thermal coal with low sulfur content, and we sell our coal primarily to domestic and foreign electric utilities. We do not produce any metallurgical coal. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation and steam output. In 2014, the coal we produced generated approximately 4% of the electricity produced in the U.S. As of December 31, 2014, we controlled approximately 1.1 billion tons of proven and probable reserves.

In 2012, we acquired the Youngs Creek project. It is a permitted but undeveloped surface mine project in the Northern PRB region located 13 miles north of Sheridan, Wyoming, contiguous with the Wyoming-Montana state line. The Youngs Creek project is approximately seven miles south of our Spring Creek Mine and seven miles from the mainline railroad, and is near the Crow project. We have not yet been able to classify the Youngs Creek project mineral rights as proven and probable reserves as they remain subject to further exploration and evaluation. In 2013, we entered an option to lease agreement and a corresponding exploration agreement with the Crow Tribe of Indians. This coal project (Crow project) is located on the Crow Indian Reservation in southeast Montana. We are in the process of evaluating the development options for the Youngs Creek project and the Crow project and believe that their proximity to the Spring Creek Mine represents an opportunity to optimize our mine developments in the Northern PRB. For purposes of this report, the term Northern PRB refers to the area within the PRB that lies within Montana and the northern part of Sheridan County, Wyoming.

We continue to develop our sales of PRB coal and delivery services business into the Asian export market. In 2014, our logistics business was the largest U.S. exporter of thermal coal into South Korea. We continue to seek ways to increase our future export capacity through existing and proposed Pacific Northwest export terminals. In August 2014, we paid $37.0 million to secure additional committed capacity at the fully-utilized Westshore port, in British Columbia. As a result, we increased our long-term committed capacity from 2.8 million tons to 6.3 million tons initially and increasing to 7.2 million tons in 2019 and extended the term of our throughput agreement by two years through the end of 2024. In early 2015, as current international prices remain low, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons, thereby reducing our committed 2015 capacity at Westshore to 5.8 million tons. For further information regarding this transaction, please see Note 9 of Notes to Consolidated Financial Statements in Item 8.

As part of the Decker Mine divestiture transaction, we were granted a throughput option for up to 7.7 million tons per year at the proposed Millennium Bulk Terminals coal export facility in Washington State. The proposed new coal export facility is currently in the permitting stage and is planned to be developed in two phases. Our option covers up to 3.3 million tons per year of capacity during the first phase of development and an additional 4.4 million tons per year once the second phase of development is reached. Our throughput capacity will have an initial term of 10 years, with four renewal options for five-year terms. Our option is exercisable following the successful completion of the ongoing permit process, which is currently in the EIS phase. The timing and outcome of the permit process are uncertain.

Table of Contents

We also have a throughput option agreement with SSA Marine, which provides us with an option for up to 17.6 million tons of capacity per year through the planned dry bulk cargo Gateway Pacific Terminal at Cherry Point in Washington State. Our potential share of capacity will depend upon the ultimate capacity of the terminal and is subject to the terms of the option agreement. The terminal will accommodate cape size vessels. Our option is exercisable following the successful completion of the ongoing permit process, which is currently in the EIS phase. The timing and outcome of the permit process are uncertain.

For information regarding our revenue and long-lived assets by geographic area, as well as revenue from external customers, Adjusted EBITDA and total assets by segment, please see Note 24 of Notes to Consolidated Financial Statements in Item 8.

Segment Information

We have reportable segments of Owned and Operated Mines, Logistics and Related Activities, and Corporate and Other.

Our Owned and Operated Mines segment is characterized by the predominant focus on thermal coal production where the sale occurs at the mine site and where title and risk of loss pass to the customer at that point. This segment includes our Antelope Mine, Cordero Rojo Mine, and Spring Creek Mine. Sales in this segment are primarily to domestic electric utilities; although a portion is made to our Logistics and Related Activities segment. Sales between reportable segments are priced based on prevailing market prices. Our mines utilize surface mining extraction processes and are all located in the PRB. The gains and losses resulting from our domestic coal futures contracts and WTI derivative financial instruments are reported within this segment.

Our Logistics and Related Activities segment is characterized by the services we provide to our international and domestic customers where we deliver coal to the customer at a terminal or the customer s plant or other delivery point, remote from our mine site. Services provided include: the purchase of coal from third parties or from our owned and operated mines, at market prices, as well as the contracting and coordination of the transportation and other handling services from third-party operators, which are typically rail and terminal companies. Title and risk of loss are retained by the Logistics and Related Activities segment through the transportation and delivery process. Title and risk of loss pass to the customer in accordance with the contract and typically occur at a vessel loading terminal, a vessel unloading terminal or an end use facility. Risk associated with rail and terminal take-or-pay agreements is also borne by the Logistics and Related Activities segment. The gains and losses resulting from our international coal forward derivative financial instruments are reported within this segment. Port access contract rights and related amortization are also included in this segment.

Our Corporate and Other segment includes results relating to broker activity, our previous share of the Decker Mine operations, which was sold on September 12, 2014, and unallocated corporate costs and assets. All corporate costs, except Board of Directors related expenses, are allocated to the segments based upon their relative percentage of certain financial metrics.

Eliminations represent the purchase and sale of coal between reportable segments and the associated elimination of intercompany profit or loss in inventory.

Core Business Operations

Our key business drivers include the following:

- the volume of coal sold from our owned and operated mines;
- the price for which we sell our coal;
- the costs of mining, including labor, repairs and maintenance, fuel, explosives, depreciation of capital equipment, and depletion of coal leases;
- capital expenditures to acquire property, plant and equipment;
- the volume of deliveries coordinated by our Logistics and Related Activities segment to customer contracted destinations;
- the revenue we receive for our logistics services;

Table of Contents

- the costs for logistics services, rail and port charges for coal sales made on a delivered basis, including demurrage and any take-or-pay charges; and

- the results of our derivative financial instruments.

The volume of coal that we sell in any given year is driven by global and domestic demand for coal-generated electric power. Demand for coal-generated electric power may be affected by many factors including weather patterns, natural gas prices, railroad performance, the availability of coal-fired and alternative generating capacity and utilization, environmental and legal challenges, political and regulatory factors, energy policies, international and domestic economic conditions, and other factors discussed in this Item 7 and in Item 1A Risk Factors.

The price at which we sell our coal is a function of the demand relative to the supply for coal. We typically enter into multi-year contracts with our customers, which helps mitigate the risks associated with any short-term imbalance in supply and demand. We typically seek to enter each year with expected production effectively fully sold. This strategy helps us run our mines at predictable production rates, which improves control of operating costs.

As is common in the PRB, coal seams at our existing mines naturally deepen, resulting in additional overburden to be removed at additional cost. We have experienced increased operating costs for longer haul distances, maintenance and supplies, and employee wages and salaries. We use derivative financial instruments to help manage certain exposures to diesel fuel prices.

We incur significant capital expenditures to maintain, update and expand our mining equipment, surface land holdings and coal reserves. As the costs of acquiring federal coal leases and associated surface rights increase, our depletion costs also increase. As of December 31, 2014, we controlled approximately 1.1 billion tons of proven and probable coal reserves.

The volume of coal sold on a delivered basis is influenced by international and domestic market conditions. Our ability to increase our international coal sales volumes is currently limited by available port capacity.

Coal sold on a delivered basis to customer contracted destinations, including sales to Asian customers, involves us arranging and paying for logistics services, which can include rail, rail car hire, and port charges, including any demurrage incurred and other costs. These logistics costs are affected by volume, various scheduling considerations, and negotiated rates for rail and port services. We have exposure to take-or-pay obligations for our rail and port committed capacities. We are also incurring costs to investigate and pursue development of additional port opportunities.

We entered into coal forward and futures contracts that are scheduled to settle at various dates through 2016 to hedge a portion of our export and domestic coal sales prices. We have also entered into WTI derivative financial instruments to hedge our diesel fuel costs.

Current Considerations

Owned and Operated Mines Segment

Throughout 2014, our domestic coal shipments were negatively impacted by the performance of the railroads, which reduced our shipments to 85.9 million tons compared our contracted position of over 90 million tons. In the fourth quarter, we started to see some improvement in railroad performance, particularly in the Southern PRB. Customers are continuing to rebuild their stockpiles from low inventories resulting in improved shipments early in 2015. Our mines are well positioned with equipment, manpower, and inventory to meet customer demand. Because of the low shipments in 2014, approximately 3 million tons of contracted sales will be carried over to the first half of 2015.

Operating costs were reduced as the operations focused on reducing overburden movement in line with lower shipments and lowering variable costs while containing other controllable costs. Costs were also reduced as we moved out of a higher cost pit at Cordero Rojo Mine, benefitted from lower explosives pricing, and reduced our use of outside contractors by bringing work in house. With the fall in oil prices, we have also entered into additional oil hedging transactions. These are expected to result in a benefit of approximately $24 million to our Adjusted EBITDA and cash flow in 2015 compared to 2014.

Execution of our plan to reduce production at Cordero Rojo Mine proceeded well during 2014. The mine has started 2015 running at its new annual rate of approximately 28 million tons with a reduced workforce and smaller equipment base. Mobile equipment is being redeployed; a shovel has been transferred from Cordero Rojo Mine to Antelope Mine and a dragline is planned to be moved soon. Transfers of employees between sites and normal attrition have allowed us to complete the reduction at Cordero Rojo Mine without any layoffs.

Table of Contents

The increased natural gas production and current mixed winter have led to a drop in natural gas prices and an increase in coal and gas inventories. This has recently put downward pressure on coal and gas prices. However, we are experiencing some help with fuel costs due to the large drop in oil prices and would expect the rapid slowdown in drilling that is occurring in many U.S. oil and gas fields could lead to increased pricing for gas. The level of cooling demand this summer will also have an impact on coal and gas pricing in the second half of the year.

For 2015, we currently expect total U.S. coal demand to be lower than 2014 due to low natural gas prices and some plant closures resulting from MATS regulation. Customers rebuilding inventories and increased utilization from existing operating units will partially offset these declines. Additionally, our customers will benefit from lower oil prices through reduced rail fuel surcharges, which should make their coal burning plants more economical. While we expect total U.S. demand to decline, we are forecasting that PRB demand should be relatively stable for 2015 compared to 2014.

Logistics and Related Activities Segment

The volume of Asian export deliveries through Westshore decreased by 14% in 2014 compared to 2013. Shipments were impacted by rail service issues. Additionally, we sought to only deliver on committed contracts and did not seek additional sales at the prevailing low export prices. Along with weak international market prices for seaborne coal, this resulted in lower revenue in 2014. The decrease in revenue from our international logistics customers was partially offset by a higher volume of domestic logistics deliveries in 2014 compared to 2013.

Our forward sales hedging program mitigated some of the impact of lower spot prices with a realized gain of $27.0 million in 2014. Demurrage costs were unusually high in the fourth quarter as rail interruptions slowed deliveries to Westshore causing delays in loading vessels.

Internationally, we continue to see growing demand for PRB coal and logistics services from our Asian customers. For 2014, China s electric generation grew an estimated 5 percent, with all of the growth coming from hydroelectric and nuclear power while thermal generation remained flat for the year. Thermal coal imports into China, which includes lignite, were 175 million tonnes for 2014, up 2 million tonnes over 2013 levels. Although uncertainty regarding China s economic growth rates, environmental regulations, and the strong U.S. dollar are creating headwinds, we expect growing demand in Asia for coal, together with reduced capital investments by producers, will eventually overcome the current oversupply. However, current international prices remain low, and as a result, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons. Consequently we now expect full year export shipments through Westshore of approximately 5.8 million tons. For 2015, a key driver of our Adjusted EBITDA will be the price we achieve for our export sales and logistics services. We are working to maximize our sales price relative to the Newcastle index, minimizing our take or pay exposure, recognizing lower fuel surcharges on rail rates, and realizing our hedge position to minimize our logistics loss.

2015 Outlook

Due to lower domestic shipments from previously announced reductions in 8400 Btu production from our Cordero Rojo Mine and the current oversupply of thermal coal in both the domestic and international coal markets leading to weak coal pricing in the short term, 2015 results are expected to be lower than 2014 results.

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to various matters, including air quality standards, water pollution, plant and wildlife protection, the discharge of materials into the environment and the effects of mining on surface and groundwater quality and availability. These laws and regulations have had, and will continue to have, a significant adverse effect on our production costs and our competitive position relative to certain other sources of electricity generation. Future laws, regulations or orders, including those relating to global climate change, may 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. See Item 1 Business Environmental and Other Regulatory Matters.

In June 2014, the EPA announced its proposed New Source Performance Standards under the Clean Air Act for reducing carbon dioxide emissions from existing fossil-fired power plants. This proposed rule aims to cut carbon dioxide emissions from existing power plants by 30% from the 2005 levels by 2030, with emission reductions scheduled to commence in 2020. The EPA has announced its plans to finalize the rule by June 1, 2015, and further proposes that states will have until June 30, 2016 to submit plans to implement the finalized rule. For now, this rule has just been proposed, and we are not in a position to determine what the outcome of any rulemaking process or legal challenges to the rule will be. Nine states have already filed a legal challenge to the proposed rulemaking. Nevertheless, if the EPA were to finalize the rule

Table of Contents

along the lines of the proposal, the market for coal would be decreased, potentially significantly. While we believe that we are similarly situated with other producers of coal relative to any final rule that may be adopted by the EPA, we are not in a position to make any meaningful determination about the extent of the impacts to our operations at this early stage in the rulemaking process.

Years Ended December 31, 2014, 2013 and 2012

Summary

The following table summarizes key results (in millions):

	Year Ended December 31, 2014	2013	2012	Percent Change 2014 vs 2013	2013 vs 2012
Total tons sold	87.1	89.1	93.0	(2.2)%	(4.2)%
Total revenue	$ 1,324.0	$ 1,396.1	$ 1,516.8	(5.2)	(8.0)
Net income	$ 79.0	$ 52.0	$ 173.7	51.9	(70.1)
Adjusted EBITDA (1)	$ 201.9	$ 218.6	$ 338.8	(7.6)	(35.5)
Adjusted EPS (1)	$ 0.19	$ 0.73	$ 2.15	(74.0)%	(66.0)%

(1) Non-GAAP measure; please see definition in Item 6 and reconciliation below.

Adjusted EBITDA and Adjusted EPS

The following tables present a reconciliation of net income (loss) to Adjusted EBITDA, diluted earnings (loss) per common share to Adjusted EPS, and segment Adjusted EBITDA to net income (loss) (in millions, except per share amounts):

Adjusted EBITDA

	Year Ended December 31, 2014	2013	2012
Net income (loss)	$ 79.0	$ 52.0	$ 173.7
Interest income	(0.3)	(0.4)	(1.1)
Interest expense	77.2	41.7	36.3
Income tax (benefit) expense	34.9	11.6	62.6
Depreciation and depletion	112.0	100.5	94.6

EBITDA		302.8		205.3		366.1
Accretion		15.1		15.3		13.2
Tax agreement expense (benefit) (1)		(58.6)		10.5		(29.0)
Derivative financial instruments:						
Exclusion of fair value mark-to-market losses (gains)(2)	$ (7.8)		$ (25.6)		$ (22.8)	
Inclusion of cash amounts received (paid)(3)(4)	24.7		13.0		11.2	
Total derivative financial instruments		16.9		(12.6)		(11.5)
Gain on sale of Decker Mine interest		(74.3)				
Expired significant broker contract						
Adjusted EBITDA		$ 201.9		$ 218.6		$ 338.8

---

(1) Changes to related deferred taxes are included in income tax expense.

(2) Fair value mark-to-market (gains) losses reflected on the statement of operations.

(3) Cash amounts received and paid reflected within operating cash flows.

(4) Excludes premiums paid at contract inception during the period	$ 4.0	$	$

Table of Contents

Adjusted EBITDA by Segment

	Year Ended December 31, 2014		2013		2012	
Owned and Operated Mines						
Adjusted EBITDA		$ 197.0		$ 202.0		$ 283.3
Depreciation and depletion		(107.6)		(98.9)		(89.2)
Accretion expense		(11.7)		(11.0)		(9.5)
Derivative financial instruments:						
Exclusion of fair value mark-to-market gains (losses)	$ (13.6)		$ (0.3)		$ 0.1	
Inclusion of cash amounts (received) paid(1)	2.3		0.3			
Total derivative financial instruments		(11.3)				0.1
Other		(0.3)		(2.6)		0.9
Operating income (loss)		66.1		89.5		185.6
Logistics and Related Activities						
Adjusted EBITDA		4.1		11.4		57.1
Derivative financial instruments:						
Exclusion of fair value mark-to-market gains (losses)	21.4		26.0		22.6	
Inclusion of cash amounts (received) paid	(27.0)		(13.2)		(11.2)	
Total derivative financial instruments		(5.6)		12.8		11.4
Other		(0.1)		(0.1)		
Operating income (loss)		(1.6)		24.1		68.4
Corporate and Other						
Adjusted EBITDA		2.1		6.0		
Depreciation and depletion		(4.5)		(1.6)		(5.3)
Accretion expense		(3.4)		(4.3)		(3.7)
Gain on sale of Decker Mine interest		74.3				
Other				(0.5)		(1.6)
Operating income (loss)		68.5		(0.4)		(10.5)
Eliminations						
Adjusted EBITDA		(1.2)		(0.8)		(1.6)
Operating loss		(1.2)		(0.8)		(1.6)
Consolidated operating income		131.8		112.4		241.9
Interest income		0.3		0.4		1.1
Interest expense		(77.2)		(41.7)		(36.3)
Tax agreement (expense) benefit		58.6		(10.5)		29.0
Other, net		(0.2)		2.4		(0.8)
Income tax (expense) benefit		(34.9)		(11.6)		(62.6)
Earnings from unconsolidated affiliates, net of tax		0.6		0.6		1.6
Net income (loss)		$ 79.0		$ 52.0		$ 173.7

(1) Excludes premiums paid at contract exception during the period.	$ 4.0	$	$

Table of Contents

Adjusted EPS

[redacted]

Diluted earnings (loss) per common share		$ 1.29		$ 0.85		$ 2.85
Tax agreement expense (benefit) including tax impacts of IPO and Secondary Offering		(0.73)		0.01		(0.58)
Derivative financial instruments:						
Exclusion of fair value mark-to-market gains	$ (0.08)		$ (0.27)		$ (0.24)	
Inclusion of cash amounts received(1)	0.25		0.14		0.12	
Total derivative financial instruments		0.17		(0.13)		(0.12)
Refinancing transaction:						
Exclusion of cash interest for early retirement of debt	0.14					
Exclusion of non-cash interest for deferred finance fee write-off	0.08					
Total refinancing transaction		0.22				
Gain on sale of Decker Mine interest		(0.76)				
Expired significant broker contract						
Adjusted EPS		$ 0.19		$ 0.73		$ 2.15
Weighted-average dilutive shares outstanding (in millions)		61.3		61.2		60.9

---

(1) Excludes the per share impact of premiums paid at contract inception during the period	$ 0.04	$	$

Results of Operations

Revenue

The following table presents revenue (in millions except per ton amounts):

	Year Ended December 31, 2014	2013	2012	Percent Change 2014 vs 2013	2013 vs 2012
Owned and Operated Mines					
Realized price per ton sold	$ 13.01	$ 13.08	$ 13.19	(0.5)%	(0.8)%
Tons sold	85.9	86.0	90.6	(0.1)	(5.1)
Coal revenue	$ 1,117.9	$ 1,125.5	$ 1,195.7	(0.7)	(5.9)
Other revenue	$ 14.1	$ 12.0	$ 10.0	17.5	20.0
Logistics and Related Activities					

Total tons delivered		5.1		5.5		5.8	(7.3)	(5.2)
Asian export tons		4.0		4.7		4.4	(14.9)	6.8
Revenue	$	224.9	$	265.9	$	338.8	(15.4)	(21.5)
Corporate and Other								
Revenue	$	22.8	$	49.4	$	38.0	(53.8)	30.0
Eliminations of intersegment sales								
Revenue	$	(55.7)	$	(56.7)	$	(65.7)	(1.8)	(13.7)
Total Consolidated								
Revenue	$	1,324.0	$	1,396.1	$	1,516.8	(5.2)%	(8.0)%

Table of Contents

Owned and Operated Mines Segment

Revenue decreased slightly in 2014 compared to 2013 due primarily to a slightly lower average realized price per ton sold. Although customer demand has been strong, prices continue to remain low due to low natural gas prices and mild weather. Shipments for 2014 continued to be impacted by rail service interruptions. The lack of adequate rail service to both our domestic utility customers and our international logistics customers was attributed to over committed rail resources and intermittent weather-related disruptions.

Revenue decreased in 2013 compared to 2012 due to a lower realized price per ton sold and fewer tons shipped. Spot prices were lower for indexed tons sold during 2013 as a result of the current coal market conditions. The combination of disruptive weather, a series of operational issues at one of our long term customers, and weak rail service resulted in lower than expected shipments during 2013 compared to 2012. The lack of adequate rail service to both our domestic utility customers and our international logistics customers was attributed to competing demands for rail crews from increased crude oil and grain railings.

Logistics and Related Activities Segment

Our Asian delivered sales are priced broadly in line with a number of relevant international coal indices adjusted for energy content and other quality and delivery criteria. These indices include the Newcastle benchmark price. Based on the comparative quality and transport costs, our delivered sales are generally priced at approximately 60% to 75% of the forward Newcastle price.

The volume of Asian deliveries through Westshore decreased in 2014 compared to 2013 primarily due to rail service issues on the northwest rail corridor. We did not make additional 2014 spot sales due to low international prices. Along with weak international market prices for seaborne coal, this resulted in lower revenue in 2014. The decrease in revenue from our international logistics customers was partially offset by a higher volume of domestic deliveries coordinated in 2014 compared to 2013.

Revenue decreased in 2013 compared to 2012 primarily as a result of lower prices on our Asian deliveries through the port. In addition, the volume of domestic deliveries coordinated decreased in 2013 compared to 2012, partially offset by higher Asian deliveries through the port.

Corporate and Other Segment

Revenue decreased in 2014 compared to 2013 primarily due to lower broker revenue and the sale of our interest in the Decker Mine on September 12, 2014.

Revenue increased in 2013 compared to 2012 primarily due to additional broker tons sold. Revenue at the Decker Mine was not significantly different between the respective periods.

Table of Contents

Cost of Product Sold

The following table presents cost of product sold (in millions except per ton amounts):

	Year Ended December 31, 2014	2013	2012	Percent Change 2014 vs 2013	2013 vs 2012
Owned and Operated Mines					
Average cost per ton sold	$ 10.19	$ 10.23	$ 9.57	(0.4)%	6.9%
Cost of product sold (produced coal)	$ 875.4	$ 880.1	$ 867.4	(0.5)	1.5
Other cost of product sold	$ 11.4	$ 10.9	$ 10.2	4.6	6.9
Logistics and Related Activities					
Cost of product sold	$ 242.0	$ 261.2	$ 280.2	(7.4)	(6.8)
Corporate and Other					
Cost of product sold	$ 20.0	$ 40.0	$ 38.7	(50.0)	3.4
Eliminations of Intersegment Sales					
Cost of product sold	$ (54.6)	$ (55.9)	$ (64.1)	(2.3)	(12.8)
Total Consolidated					
Cost of product sold	$ 1,094.2	$ 1,136.3	$ 1,132.4	(3.7)%	0.3%

Owned and Operated Mines Segment

The cost of product sold decreased primarily as a result of a reduction in overburden moved to match with lower shipments. Costs were also reduced as we moved out of a higher cost pit at Cordero Rojo Mine, benefitted from lower explosives pricing, and reduced our use of outside contractors by bringing work in house. These were offset by the impact of the $7.5 million third quarter accrual for past production taxes, which increased the average cost of produced coal by $0.09 per ton in 2014.

The cost of product sold and average cost per ton sold increased in the year ended December 31, 2013 compared to 2012 primarily as a result of cost inflation on our explosives purchases and additional labor and equipment costs associated with longer hauls and increased strip ratios.

Logistics and Related Activities Segment

Cost of product sold decreased in the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to a reduction in the volume of Asian tons delivered through Westshore, partially offset by an increase in the volume of domestic deliveries coordinated. Demurrage costs continue to be high as on-going rail interruptions slowed deliveries to Westshore causing delays loading vessels.

Cost of product sold decreased in the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to a reduction in the volume of domestic deliveries coordinated, partially offset by higher Asian tons delivered through the port and unusually high demurrage costs in 2013 as rail interruptions slowed deliveries to Westshore causing delays loading vessels.

Corporate and Other Segment

Cost of product sold decreased in the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to the lower broker tons sold and the sale of our interest in the Decker Mine on September 12, 2014.

Cost of product sold increased in the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to the additional broker tons sold partially offset by lower costs at the Decker Mine.

Table of Contents

Operating Income

The following table presents operating income (in millions):

	Year Ended December 31, 2014	2013	2012	Percent Change 2014 vs 2013	2013 vs 2012
Owned and Operated Mines					
Operating income (loss)	$ 66.1	$ 89.5	$ 185.6	(26.1)%	(51.8)%
Logistics and Related Activities					
Operating income (loss)	$ (1.6)	$ 24.1	$ 68.4	(106.6)	(64.8)
Corporate and Other					
Operating income (loss)	$ 68.5	$ (0.4)	$ (10.5)	*	(96.2)
Eliminations of Intersegment Sales					
Operating income (loss)	$ (1.2)	$ (0.8)	$ (1.6)	50.0	(50.0)
Total Consolidated					
Operating income (loss)	$ 131.8	$ 112.4	$ 241.9	17.3%	(53.5)%

* *Not meaningful*

Owned and Operated Mines Segment

In addition to the revenue and cost of product sold factors previously discussed, operating income for the year ended December 31, 2014 decreased compared to 2013 due to higher mark-to-market losses recognized of $11.8 million on the WTI derivative financial instruments, which included the $4 million premium paid, due to the recent decline in oil prices to an average forward price of $54.84 per barrel and $1.4 million on the domestic coal futures contracts. In addition, we incurred higher depreciation and depletion primarily caused by mining in higher cost lease areas.

In addition to the revenue and cost of product sold factors previously discussed, operating income decreased for the year ended December 31, 2013 compared to 2012 due to higher depreciation and depletion, a higher allocation of selling, general and administrative costs to this segment based on its relative percentage of financial metrics used, and additional project development costs in 2013 as compared to 2012.

Logistics and Related Activities Segment

In addition to the revenue and cost of product sold factors previously discussed, operating income decreased for the year ended December 31, 2014 compared to 2013 due to lower gains recognized on the mark-to-market impact from our international coal forward contracts as a result of declining international coal market prices.

The decrease in operating income for the year ended December 31, 2013 compared to 2012 was due to the revenue and cost of product sold factors previously discussed and was partially offset by a $3.4 million higher mark-to-market gain in 2013 as compared to 2012 from our international coal forward contracts as a result of declining international benchmark coal prices. In addition, there was a reduction in the allocation of selling, general and administrative costs to this segment based on its relative percentage of financial metrics used, and lower project development costs in 2013 as compared to 2012.

Corporate and Other Segment

Operating income increased for the year ended December 31, 2014 compared to 2013 primarily due to the $74.3 million gain recognized on the sale of our 50% non-operating interest in the Decker Mine, partially offset by the revenue and cost of product sold factors previously discussed.

Operating loss decreased for the year ended December 31, 2013 compared to 2012 primarily due to the revenue and cost of product sold factors previously discussed and lower depreciation and accretion expense partially offset by higher project development costs in 2013 as compared to 2012.

Table of Contents

Other Expense

The following table presents other expense (in millions):

	Year Ended December 31,			Percent Change	
	2014	2013	2012	2014 vs 2013	2013 vs 2012
Other income (expense)	$ (18.5)	$ (49.3)	$ (7.1)	(62.5)%	594.4%

Other expense for the year ended December 31, 2014 as compared to 2013 decreased primarily as a result of the adjustment to the tax agreement liability due to the acceleration and release agreement signed with Rio Tinto, which terminated the TRA. This $58.6 million gain was partially offset by a $35.5 million increase in interest expense consisting of $21.5 million related to the early retirement of debt and refinancings and $29.2 million due to less interest capitalized in 2014 as compared to 2013, partially offset by $9.5 million lower interest on our senior notes and $5.2 million lower imputed interest on our federal coal lease obligations.

Other expense for the year ended December 31, 2013 included a $10.5 million charge as compared to a $29.0 million benefit in 2012 as a result of the annual tax agreement liability adjustment. In addition, interest expense increased as compared to 2012 due to a reduction in the amount of interest capitalized in the current period as certain projects were put into service.

Income Tax Provision

The following table presents income tax provision (in millions):

	Year Ended December 31,			Percent Change	
	2014	2013	2012	2014 vs 2013	2013 vs 2012
Income tax benefit (expense)	$ (34.9)	$ (11.6)	$ (62.6)	200.9%	(81.5)%
Effective tax rate	30.8%	18.4%	26.7%	67.4%	(31.1)%

Our statutory income tax rate, including state income taxes, was approximately 37%. The difference from that rate for the years ended December 31, 2014 and 2013 was primarily related to the release of a portion of our valuation allowance on our deferred tax assets that we determined are more likely than not to be realized. In addition, in 2013, the percentage depletion deduction had a greater impact than in 2014 due to a shift in the mix of income from our various mines.

Our statutory income tax rate, including state income taxes, was approximately 37%. The difference from that rate for the years ended December 31, 2013 and 2012 was primarily related to adjustments to the deferred tax valuation allowance resulting from the third quarter annual calculation of our estimate of future taxable income and the impact of the percentage depletion deduction.

Liquidity and Capital Resources

	Year Ended December 31, 2014	2013 (in millions)	2012
Cash and cash equivalents	$ 168.7	$ 231.6	$ 197.7
Investments in marketable securities		80.7	80.3
Total	$ 168.7	$ 312.3	$ 278.0

In addition to our cash and cash equivalents, our primary sources of liquidity are cash from our operations, investments in marketable securities, and borrowing capacity under our revolving credit facility and A/R Securitization Program. In addition, we organized a capital leasing program that could grow over time from its current balance of $9.0 million up to $150 million for some of our capital equipment purchases subject to the conditions in the master lease agreement. These programs provide flexibility and liquidity to our capital structure. For further details on the A/R Securitization Program and credit facility, see below. For further details on the capital leasing program, see Note 14 of Notes to Consolidated Financial Statements in Item 8. Cash from operations depends on a number of factors beyond our control, such as the market price for our coal, revenue for our logistics services, the quantity of coal required by our customers, coal-fired electricity demand, regulatory changes and energy policies impacting our business, our costs of operations including the market price we pay for diesel fuel and other input costs, as well as costs of logistics including rail and port charges, and other risks and uncertainties, including those discussed in Item 1A Risk Factors.

Investments in marketable securities include highly-liquid securities that are investment grade. Our investment policy has the objective of minimizing the potential risk of principal loss and is intended to limit our credit exposure to any single issuer. Individual securities have various maturity dates; however, it is our expectation that we could sell any individual security in the secondary market on short notice allowing for improved liquidity.

Certain of our subsidiaries are parties to the A/R Securitization Program. In January 2013, we formed Cloud Peak Energy Receivables LLC (the SPE), a special purpose, bankruptcy-remote wholly-owned subsidiary to purchase, subject to certain exclusions, in a true sale, trade receivables generated by certain of our subsidiaries without recourse (other than customary indemnification obligations for breaches of specific representations and warranties), and then transfer undivided interests in up to $75 million of those accounts receivable to a financial institution for cash borrowings for our ultimate benefit. The total borrowings are limited by eligible accounts receivable, as defined under the terms of the A/R Securitization Program. At December 31, 2014, the A/R Securitization Program would have allowed for $52.1 million of borrowing capacity. There were no borrowings outstanding from the A/R Securitization Program at December 31, 2014.

On January 23, 2015, we entered into an agreement extending the term of the A/R Securitization Program until January 23, 2018. All other terms of the program have remained substantially the same.

On February 21, 2014, CPE Resources entered into a five-year Credit Agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders (the Credit Agreement). The Credit Agreement provides us with a senior secured revolving credit facility with a capacity of up to $500 million that can be used to borrow funds or issue letters of credit. The borrowing capacity under the Credit Agreement is reduced by the amount of letters of credit issued, which may be up to $250 million. Subject to the satisfaction of certain conditions, we may elect to increase the size of the revolving credit facility and/or request the addition of one or more new tranches of term loans in an amount up to the greater of (i) $200 million or (ii) our EBITDA (which is defined in the Credit Agreement) for the preceding four fiscal quarters.

As of December 31, 2014, no borrowings or letters of credit were outstanding under the credit facility, and we were in compliance with the covenants contained in the Credit Agreement. Our aggregate borrowing capacity under the Credit Agreement and the A/R Securitization Program was approximately $552.1 million at December 31, 2014.

The indentures governing the senior notes impose limitations on the ability of CPE Resources and its subsidiaries to make distributions, and to extend loans and advances, to CPE Inc. Such limitations, taken as a whole, are less restrictive than those contained in the Credit Agreement. We are also required to make semi-annual interest payments on our senior notes.

The limitations in both the Credit Agreement and the indentures have not had, nor are they expected to have, a negative impact upon the ability of CPE Resources to make distributions to CPE Inc.

During 2014, we made payments of $69.4 million on the West Antelope II LBAs. We will make the final payments of $69.4 million in 2015, after which we have no further committed LBA payments. We will continue to explore opportunities to increase our reserve base by acquiring additional coal and surface rights. If we are successful in future bids for coal rights and other growth strategies, our cash flows could be significantly impacted as we would be required to make associated payments.

Capital expenditures are necessary to keep our equipment fleets updated to maintain our mining productivity and competitive position and to add new equipment as necessary. Capital expenditures (excluding capitalized interest) for 2014 were $19.9 million, of which $1.2 million was financed under capital leases. Our anticipated capital expenditures (excluding capitalized interest and federal lease payments) are expected to be between $50 million and $70 million in 2015. This range includes $20 million for the relocation of a dragline from the Cordero Rojo Mine to the Antelope Mine.

In August 2014, we entered into an acceleration and release agreement with Rio Tinto whereby we agreed to pay $45.0 million to Rio Tinto to terminate the TRA. This payment settles all future liabilities that would have been owed under the TRA. At the date of signing, we carried an undiscounted liability of $103.6 million in respect of our estimated future obligations under the TRA and anticipated making cash payments of approximately $14 million each year in 2014 and 2015 and additional payments in subsequent years.

Table of Contents

We believe our sources of liquidity will be sufficient to fund our primary ordinary course uses of cash for the next 12 months, which include our costs of coal production and logistics services, coal lease installment payments for LBAs and other coal tracts, capital expenditures, and interest on our debt.

If we do not have sufficient resources from ongoing operations to satisfy our obligations or the timing of payments on our obligations does not coincide with cash inflows from operations, we may need to use our cash on hand or borrow under our line of credit. If the obligation is in excess of these amounts, we may need to seek additional borrowing sources or take other actions. Depending upon existing circumstances at the time, we may not be able to obtain additional funding on acceptable terms or at all. In addition, our existing debt instruments contain restrictive covenants, which may prohibit us from borrowing under our revolving credit facility or pursuing certain alternatives to obtain additional funding.

We regularly monitor the capital and bank credit markets for opportunities that we believe will improve our balance sheet, and may engage, from time to time, in financing or refinancing transactions as market conditions permit. Future activities may include, but are not limited to, public or private debt or equity offerings, the purchase of our outstanding debt for cash in open market purchases or privately negotiated refinancing, extension and exchange transactions or public or private exchange offers or tender offers. Any financing or refinancing transaction may occur on a stand-alone basis or in connection with, or immediately following, other transactions.

Overview of Cash Transactions

We started 2014 with cash, cash equivalents and investments in marketable securities of $312.3 million and concluded the year ended December 31, 2014 with $168.7 million. The primary reasons for the decline were the refinancing and repayment of $100 million of our senior notes due December 15, 2017 (2017 Senior Notes), a payment of $45 million to Rio Tinto to terminate the TRA, and the payment of $37 million to Westmoreland to acquire port capacity for Westshore.

Cash Flows

	Year Ended December 31, 2014	2013 (in millions)	2012
Beginning balance - cash and cash equivalents	$ 231.6	$ 197.7	$ 404.2
Net cash provided by operating activities	98.2	180.7	247.4
Net cash used in investing activities(1)	13.4	(82.0)	(347.9)
Net cash used in financing activities	(174.4)	(64.8)	(106.0)
Ending balance - cash and cash equivalents	$ 168.7	$ 231.6	$ 197.7
Beginning balance - marketable securities	$ 80.7	$ 80.3	$ 75.2
Ending balance - marketable securities(1)	$	$ 80.7	$ 80.3

(1) Included in net cash used in investing activities is the purchase of marketable securities which are highly-liquid securities that are generally investment grade or better and are held as trading securities. Individual securities have various maturity dates; however, it is our expectation that we could sell any individual security in the secondary market allowing for improved liquidity.

The decrease in cash provided by operating activities from 2013 to 2014 was due to a decrease in net income as adjusted for noncash items and a decrease in working capital changes, primarily due to the $45.0 million payment to terminate the TRA with Rio Tinto in 2014 as compared to the annual payment of $23.5 million paid in 2013. This payment to Rio Tinto settled all future liabilities that would have been owed under the TRA. In addition, accounts receivable and inventories increased in 2014 as compared to 2013 and we paid $13.8 million in premiums in excess of par related to the refinancing of the 2017 Notes. These were partially offset by the increase in net cash received on our derivative financial instruments in 2014 as compared to 2013.

The decrease in cash provided by operating activities from 2012 to 2013 was due to a decrease in net income as adjusted for noncash items offset by an increase in working capital changes, primarily due to an increase in accounts payable and accrued expenses and decreases in inventories and payments on asset retirement obligations. These were partially offset by an increase in accounts receivable.

Table of Contents

The increase in cash provided by investing activities from 2013 to 2014 was primarily related to the net redemption of investments in marketable securities of $80.7 million and lower purchases of property, plant and equipment and capitalized interest, partially offset by the $37.0 million payment made to secure additional capacity at Westshore. This payment allowed us to increase our contracted export capacity from approximately 2.8 million tons to 6.3 million tons initially beginning in 2015. In early 2015, as current international prices remain low, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons, thereby reducing our committed 2015 capacity at Westshore to 5.8 million tons.

The decrease in cash used in investing activities from 2012 to 2013 was primarily due to the acquisition of the Youngs Creek project in 2012 and a decrease in cash paid for property, plant and equipment and capitalized interest. These were partially offset by a return of restricted cash in 2012 that did not occur in 2013.

The increase in cash used in financing activities from 2013 to 2014 was primarily due to de-levering the balance sheet by paying $100 million in principal on the $300 million of 2017 Notes. We refinanced the remaining amount with the $200 million senior notes due March 15, 2024. We also incurred additional deferred financing costs of $14.7 million related to the refinancing of the senior notes and Credit Agreement. This increase was partially offset by lower principal payments on federal coal leases.

The decrease in cash used in financing activities from 2012 to 2013 was primarily due to a decrease in principal payments on federal coal leases. Principal payments were $63.2 million in 2013 as compared to $102.2 million in 2012.

Senior Notes

We refer to the $300 million senior notes due December 15, 2019 (the 2019 Notes) and the $200 million senior notes due March 15, 2024 (the 2024 Notes) collectively as the senior notes. The 2019 Notes and 2024 Notes bear interest at fixed annual rates of 8.50% and 6.375%, respectively. There are no mandatory redemption or sinking fund payments for the senior notes. Interest payments are due semi-annually on June 15 and December 15 for the 2019 Notes and semi-annually on March 15 and September 15 for the 2024 Notes. Subject to certain limitations, we may redeem the 2019 Notes by paying specified redemption prices in excess of their principal amount prior to December 15, 2017, or by paying their principal amount thereafter. We may redeem some or all of the 2024 Notes by paying specified redemption prices in excess of their principal amount, plus accrued and unpaid interest, if any, prior to March 15, 2022, or by paying their principal amount thereafter, plus accrued and unpaid interest, if any.

The senior notes are jointly and severally guaranteed by CPE Inc. and by all of our existing and future restricted subsidiaries that guarantee our debt under our credit facility. See Senior Secured Revolving Credit Facility below. Substantially all of our current consolidated subsidiaries, excluding Cloud Peak Energy Receivables LLC, are considered to be restricted subsidiaries and guarantee the senior notes.

The indentures governing the senior notes, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness and issue preferred equity; pay dividends or distributions; repurchase equity or repay subordinated indebtedness; make investments or certain other restricted payments; create liens; sell assets; enter into agreements that restrict dividends, distributions, or other payments from restricted subsidiaries; enter into transactions with affiliates; and consolidate, merge, or transfer all or substantially all of their assets and the assets of their restricted subsidiaries on a combined basis.

Upon the occurrence of certain transactions constituting a change in control as defined in the indentures, holders of our senior notes could require us to repurchase all outstanding senior notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

Senior Secured Revolving Credit Facility

On February 21, 2014, CPE Resources entered into a five-year Credit Agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders (the Credit Agreement). The Credit Agreement provides us with a senior secured revolving credit facility with a capacity of up to $500 million that can be used to borrow funds or issue letters of credit. The borrowing capacity under the Credit Agreement is reduced by the amount of letters of credit issued, which may be up to $250 million. Subject to the satisfaction of certain conditions, we may elect to increase the size of the revolving credit facility and/or request the addition of one or more new tranches of term loans in an amount up to the greater of (i) $200 million or (ii) our EBITDA (which is defined in the Credit Agreement) for the preceding four fiscal quarters. The

Table of Contents

Credit Agreement provides for the designation of a foreign restricted subsidiary as a borrower, subject to certain conditions and approvals.

On September 5, 2014, we entered into the First Amendment to the Credit Agreement (the Amendment). The Amendment adjusted the financial covenants under the Credit Agreement, which now require us to maintain (a) a ratio of EBITDA (as defined in the Credit Agreement) for the preceding four fiscal quarters to consolidated net cash interest expense equal to or greater than 1.50 to 1 from September 30, 2014 to maturity, and (b) a ratio of senior secured funded debt less unrestricted cash and marketable securities (net secured debt) to EBITDA for the preceding four fiscal quarters equal to or less than 4.00 to 1 from September 30, 2014 to maturity. This credit facility and capital leases are considered senior secured funded debt under the covenant calculations whereas federal coal lease obligations, accounts receivable securitizations, and senior notes are not considered senior secured funded debt.

The Credit Agreement replaced our previous $500 million amended and restated credit agreement dated June 3, 2011. There were no borrowings outstanding under the previous credit facility at the time of replacement or at December 31, 2013. At the time of replacement, we recorded a charge of $2.2 million in interest expense to write off certain deferred financing costs as certain banks of the syndicate changed. We recorded $9.7 million of new deferred financing costs related to the new Credit Agreement and related Amendment. The aggregate deferred financing costs are being amortized on a straight-line basis to interest expense over the five-year term of the Credit Agreement.

The Credit Agreement also contains other non-financial covenants, including covenants related to our ability to incur additional debt or take other corporate actions. The Credit Agreement also contains customary events of default with customary grace periods and thresholds. Our ability to access the available funds under the credit facility may be prohibited in the event that we do not comply with the covenant requirements or if we default on our obligations under the Credit Agreement.

Loans under the Credit Agreement bear interest at LIBOR plus an applicable margin of 2.00% to 2.75%, depending on our net total leverage to EBITDA ratio. We pay the lenders a commitment fee between 0.375% and 0.50% per year, depending on our net total leverage to EBITDA ratio, on the unused amount of the credit facility. Letters of credit issued under the credit facility, unless drawn upon, will incur a per annum fee from the date at which they are issued between 2.00% and 2.75% depending on our net total leverage to EBITDA ratio. Letters of credit that are drawn upon are converted to loans. In addition, in connection with the issuance of a letter of credit, we are required to pay the issuing bank a fronting fee of 0.125% per annum.

Our obligations under the Credit Agreement are secured by substantially all of our assets and substantially all of the assets of certain of our subsidiaries, subject to certain permitted liens and customary exceptions for similar coal financings. Our obligations under the Credit Agreement are also supported by a guarantee by CPE Inc. and our domestic restricted subsidiaries.

Under the Credit Agreement, the subsidiaries of CPE Inc. are permitted to make distributions to CPE Inc. to enable it to pay (i) federal, state and local income and certain other taxes it incurs that are attributable to the business and operations of its subsidiaries and (ii) amounts on the tax agreement liability, which was terminated in August 2014. In addition, as long as no default under the Credit Agreement exists, the subsidiaries of CPE Inc. also may make annual distributions to CPE Inc. to fund dividends or repurchases of CPE Inc. s stock and additional distributions in accordance with certain distribution limits in the Credit Agreement. Finally, the subsidiaries of CPE Inc. may make loans to CPE Inc. subject to certain limitations in the Credit Agreement.

As of December 31, 2014, no borrowings or letters of credit were outstanding under the credit facility, and we were in compliance with the covenants contained in the Credit Agreement. Our aggregate borrowing capacity under the Credit Agreement and the A/R Securitization Program was approximately $552.1 million at December 31, 2014.

Table of Contents

Federal Coal Lease Obligations

Our federal coal lease obligations consist of amounts payable to the BLM under leases, each of which requires five equal annual payments. The remaining aggregate annual payments under our existing federal coal leases were as follows as of December 31, 2014 (in millions):

		2015
WAII North (Antelope Mine)	$	59.5
WAII South (Antelope Mine)		9.9
Total	$	69.4

We recognize imputed interest on federal coal leases based on an estimate of the credit-adjusted, risk-free rates reflecting our estimated credit rating at the inception of the lease. The carrying value reported on our balance sheet of our federal coal lease obligations was $64.0 million as of December 31, 2014. Additional amounts may be incurred should we bid and win additional coal leases in the future.

Off-Balance Sheet Arrangements

In the normal course of business, we are party to a number of arrangements that secure our performance under certain legal obligations. These arrangements include letters of credit and surety bonds. We use these arrangements primarily to comply with federal and state laws that require us to secure the performance of certain long-term obligations, such as mine closure or reclamation costs, coal lease obligations, state workers compensation, and federal black lung liabilities. These arrangements are typically renewable annually. Liabilities related to these arrangements are not reflected in our consolidated balance sheets.

As of December 31, we used surety bonds to secure outstanding obligations as follows (in millions):

		2014		2013
Reclamation obligations(1)	$	401.9	$	642.4
Lease obligations(2)		39.1		34.7
Other obligations(3)		7.9		0.5
Total off-balance sheet obligations	$	448.9	$	677.5

(1) Reclamation obligations include amounts to secure performance related to our outstanding obligations to reclaim areas disturbed by our mining activities and are a requirement under our state mining permits.

(2) Lease obligations include amounts generally required as a condition to state or federal coal leases; the amounts vary and are mandated by the governing agency.

(3) Other obligations include amounts required for exploration permits, water well construction and monitoring, exporting, and other miscellaneous items as mandated by applicable governing agencies.

Our outstanding surety bonds in respect of our reclamation, lease, and other obligations were $448.9 million at December 31, 2014 and are required by law. In addition, we were self-bonded for $200 million related to our reclamation obligations in the State of Wyoming. State statutes regulate and determine the calculation of the amounts of the bonds that we are required to hold. We do not believe that these state-mandated estimates are a true reflection of what our actual reclamation costs will be. Reclamation bond amounts represent an estimate of the near-term reclamation liability that assumes reclamation activities will be performed by a third party during the next one to five years. Because this evaluation is near-term, it is recalculated on a frequent basis, often annually. The basis for calculating bond requirements is substantially different than the requirements that apply to the determination of our asset retirement obligation (ARO) liability on our consolidated balance sheet, which is determined in accordance with U.S. GAAP. The state calculates our specific bond requirements considering assumed costs that the state would incur if they were required to complete the reclamation on our behalf. Additionally, where a multi-year bond, such as a three to five-year bond, is put into place, the state regulatory authority requires that the reclamation liability be calculated for the highest cost scenario over that period.

The carrying amount of our reclamation obligations, as determined in accordance with U.S. GAAP, which are reported in our consolidated financial statements as ARO liabilities, was $217.3 million at December 31, 2014, $1.1 million of which is classified as a current liability. We estimate our ARO liabilities based on disturbed acreage to date and the estimated cost of a third party to perform the work. The estimated ARO liabilities are also based on engineering studies and

Table of Contents

our engineering expertise related to the reclamation requirements. We also assume that reclamation will be completed after the end of the mine life based on our current reclamation area profiles, which may be a different land disturbance assumption than the state requires, as we generally perform reclamation concurrently with our mining activities. Finally, the carrying amount of our ARO liabilities reflects discounting of estimated reclamation costs using credit-adjusted, risk-free rates. For a discussion of the risks relating to our reclamation obligations, see Item 1A Risk Factors Risks Related to Our Business and Industry If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, our costs could be significantly greater than anticipated.

Because we are required by state and federal law to have these bonds or letters of credit 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 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 any credit facility then in place. For a discussion of the risks relating to our surety bonds, see Item 1A Risk Factors Risks Related to Our Business and Industry Failure to maintain our surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and materially adversely affect our ability to mine or lease coal. See Note 18 of Notes to Consolidated Financial Statements in Item 8.

Contractual Obligations

As of December 31, 2014, we had the following contractual obligations (in millions):

	Total	2015	2016-2017	2018-2019	2020 and Thereafter
Senior notes(1)	$ 500.0	$	$	$ 300.0	$ 200.0
Coal lease obligations(2)	64.0	64.0			
Interest related to long-term obligations(3)	254.1	43.7	76.5	76.5	57.4
Operating and capital lease obligations	12.4	2.3	4.4	4.3	1.4
Coal purchase obligations	2.6	2.6			
Transportation and supplies(4)	703.7	128.5	117.5	119.7	338.0
Capital expenditure obligations(5)	36.4	12.7		23.7	
Total	$ 1,573.2	$ 253.8	$ 198.4	$ 524.2	$ 596.8

(1) CPE Resources issued $500 million aggregate principal amount of senior notes in two tranches due 2019 and 2024. CPE Resources is a party to a $500 million Credit Agreement, none of which had been drawn as of December 31, 2014. See Notes 12 and 14 of Notes to Consolidated Financial Statements in Item 8.

(2) Coal lease obligations include our discounted payment obligations under federal coal leases, private coal leases and land purchase notes. See Note 13 of Notes to Consolidated Financial Statements in Item 8.

(3) As of December 31, 2014, we had outstanding commitments for interest related to our senior notes, private coal lease and land purchase notes, and imputed interest for our federal coal lease obligations. See Notes 12 and 13 of Notes to Consolidated Financial Statements in Item 8.

(4) As of December 31, 2014, we had outstanding commitments for transportation of $691.5 million and commitments for the purchase of supplies to be used in our mining operations of $12.2 million. See Note 18 of Notes to Consolidated Financial Statements in Item 8.

(5) As of December 31, 2014, we had outstanding commitments for capital expenditures which are not included on our consolidated balance sheet. Included in this amount is a contractual obligation to purchase land adjacent to our Antelope Mine, whereby the seller may require us to pay a purchase price of up to $23.7 million prior to April 2018. See Note 18 of Notes to Consolidated Financial Statements in Item 8.

This table does not include our estimated AROs. As discussed in Critical Accounting Policies and Estimates Asset Retirement Obligations below, the current and noncurrent carrying amount of our AROs involves a number of estimates, including the amount and timing of the payments to satisfy these obligations. The timing of payments is based on numerous factors, including projected mine closing dates. Based on our assumptions, the carrying amount of our AROs (excluding concurrent reclamation and amounts due in the current period) as determined in accordance with U.S. GAAP was $216.2 million as of December 31, 2014. See Note 16 of Notes to Consolidated Financial Statements in Item 8.

Table of Contents

Critical Accounting Policies and Estimates

The preparation of consolidated financial statements and related disclosures in accordance with accounting principles generally accepted in the U.S. requires us to make judgments, estimates, and assumptions that affect the reported amounts of assets, liabilities, and revenue and expenses, as well as the disclosure of contingent assets and liabilities. We base our judgments, estimates, and assumptions on historical information and other known factors that we deem relevant. Estimates are inherently subjective, as significant management judgment is required regarding the assumptions utilized to calculate accounting estimates in our consolidated financial statements, including the notes thereto. Actual results could differ materially from the amounts reported based on variability in factors affecting these consolidated financial statements. Our significant accounting policies are described in Note 3 of Notes to Consolidated Financial Statements in Item 8. This section describes those accounting policies and estimates that we believe are critical to understanding our consolidated financial statements.

Revenue Recognition

We recognize revenue from a sale when persuasive evidence of an arrangement exists, the price is determinable, the product has been delivered, title has transferred to the customer and collection of the sales price is reasonably assured. Some coal supply agreements provide for price adjustments based on variations in quality characteristics of the coal shipped. In certain cases, a customer s analysis of the coal quality is binding and the results of the analysis are received on a delayed basis. In these cases, we estimate the amount of the quality adjustment and adjust the estimate to actual when the information is provided by the customer. Historically, such adjustments have not been material.

Asset Retirement Obligations

Our AROs arise from the SMCRA and similar state statutes. These regulations require that we, upon closure of a mine, restore the mine property in accordance with an approved reclamation plan issued in conjunction with our mining permit. Our AROs are recorded initially using estimates of future third-party costs.

To determine our AROs, we calculate on a mine-by-mine basis the present value of estimated future reclamation cash flows based upon each mine s permit requirements, estimates of the current disturbed acreage subject to reclamation, which is based upon approved mining plans, estimates of future reclamation costs, and assumptions regarding the mine s productivity, which are based on engineering estimates that include estimates of volumes of earth and topsoil to be moved, the purchase and use of particular pieces of large mining equipment to move the earth, and the operating costs for those pieces of equipment. These cash flow estimates are discounted at credit-adjusted, risk-free rates to arrive at a present value of estimated future reclamation costs. Upon initial recognition of the liability, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset.

The amount recorded as an ARO for a mine may change as a result of mining permit changes granted by mining regulators, changes in the timing of mining activities and the mine s productivity from original estimates and changes in the estimated costs or the timing of reclamation activities. We periodically update estimates of cash expenditures to meet each mine s reclamation requirements and we adjust the ARO to fair value in accordance with U.S. GAAP, which generally requires a measurement of the present value of any change in estimated reclamation costs using credit-adjusted, risk-free rates. If a reduction of the asset retirement obligation exceeds the carrying amount of the related asset retirement cost, the adjustment is recorded as a reduction of depletion expense. Annually, we analyze AROs on a mine-by-mine basis and, if necessary, adjust the balance to take into account any changes in estimates. In addition, on an interim basis, we may update the liability based on significant changes to the life of mine.

Seasonality

Our customers generally respond to seasonal variations in electricity demand based upon the number of heating degree days and cooling degree days. Due to utility stockpile management, our coal sales do not experience the same direct seasonal volatility; however, extended mild weather patterns can directly impact the demand for our coal. In addition, the mild weather can reduce demand and therefore, the price for natural gas, which can displace coal in electricity generation. Our sales typically benefit from decreases in customers stockpiles due to high electricity demand. Conversely, when these stockpiles increase, demand for our coal will typically soften. Further, our ability to deliver coal is impacted by the seasons. For example, in the spring and summer of 2011, the Midwest region experienced severe flooding which disrupted rail service to mines in the PRB and affected the ability of those customers who were impacted by the flooding to take coal deliveries.

Global Climate Change

Enactment of currently proposed or future laws or regulations regarding emissions from the combustion of coal by the U.S. or some of its states or by other countries, or other actions to limit such emissions, like the creation of mandatory use requirements for renewable fuel sources, could result in electricity generators further switching from coal to other fuel sources. Public concern and the political environment may also continue to materially and adversely impact future coal demand and usage to generate electricity, regardless of applicable legal and regulatory requirements. Additionally, the creation and issuance of subsidies designed to encourage use of alternative energy sources could decrease the demand of coal as an energy source. The potential financial impact on us as a result of these factors will depend upon the degree to which electricity generators diminish their reliance on coal as a fuel source as a result thereof. That, in turn, will depend on a number of factors, including the appeal and design of the subsidies being offered, the specific requirements imposed by any such laws or regulations such as mandating use by utilities of renewable fuel sources, the time periods over which those laws or regulations would be phased in and the state of commercial development and deployment of carbon capture and storage technologies. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws or regulations may have on our results of operations, financial condition or cash flows. See Item 1 Business Environmental and Other Regulatory Matters Global Climate Change and Item 1A Risk Factors for additional discussion regarding how climate change and other environmental regulatory matters may materially adversely impact our business.

Newly Adopted Accounting Standards and Recently Issued Accounting Pronouncements

See Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of newly adopted accounting standards and recently issued accounting pronouncements.

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

We define market risk as the risk of economic loss as a consequence of the adverse movement of market rates and prices or credit standings. We believe our principal market risks are commodity price risk, interest rate risk and credit risk.

Commodity Price Risk

Market risk includes the potential for changes in the market value of our coal portfolio. Historically, we have principally managed the commodity price risk for our coal contract portfolio through the use of long-term coal supply agreements of varying terms and durations. As of December 31, 2014, we had committed to sell approximately 77 million tons during 2015, of which 69 million tons are under fixed-price contracts. A $1 change to the average coal sales price per ton for these 8 million unpriced tons would result in an approximate $8 million change to the coal sales revenue. In addition, we entered into certain forward financial contracts linked to Newcastle coal prices to help manage our exposure to variability in future international coal prices. As of December 31, 2014, we held coal forward contracts for approximately 0.6 million tons which will settle in 2015 and 2016, of which 0.4 million tons have been fixed under offsetting contracts. A $1 change to the market index price per ton for these coal forward contracts would result in an approximate $0.2 million change to operating income (expense). As of December 31, 2014, we held domestic coal futures contracts for approximately 2.1 million tons, which will settle in 2015 and 2016. A $1 change to the market index price per ton for these futures contracts would result in an approximate $2.1 million change to operating income (expense).

We also face price risk involving other commodities used in our production process, primarily diesel fuel. Based on our projections of our usage of diesel fuel for the next 12 months, and assuming that the average cost of diesel fuel increases by 10%, we would incur additional fuel costs of approximately $9.6 million over the next 12 months. In addition, we use derivative financial instruments to manage certain exposures to diesel fuel prices. If WTI decreases by 10%, we would incur additional costs of $2.1 million. The terms of the program are disclosed in Note 7 of Notes to Consolidated Financial Statements in Item 8.

Interest Rate Risk

Our revolving credit facility and A/R Securitization Program are subject to an adjustable interest rate. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. We had no outstanding borrowings under our credit facility or A/R Securitization Program as of December 31, 2014. If we borrow funds under the revolving credit facility or A/R Securitization Program, we may be subject to increased sensitivity to interest rate movements. The $9.0 million of borrowings under the capital lease program are also subject to variable interest rates although any change to the rate would not have a significant impact on cash flow. Any future debt

Table of Contents

arrangements that we enter into may also have adjustable interest rates that may increase our sensitivity to interest rate movements.

Credit Risk

We are exposed to credit loss in the event of non-performance by our counterparties, which may include end-use customers, trading houses, brokers, and financial institutions that serve as counterparties to our derivative financial instruments and hold our investments. We attempt to manage this exposure by entering into agreements with counterparties that meet our credit standards and that are expected to fully satisfy their obligations under the contracts. These steps may not always be effective in addressing counterparty credit risk.

When appropriate (as determined by our credit management function), we have taken steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps include obtaining letters of credit and requiring prepayments for shipments. See Item 1A Risk Factors Risks Related to Our Business and Industry We are exposed to counterparty risk with our customers, trading partners, financial institutions, and other parties with whom we conduct business.

Table of Contents

Item 8. ***Financial Statements and Supplementary Data.***

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Cloud Peak Energy Inc.,

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and comprehensive income, equity, and cash flows present fairly, in all material respects, the financial position of Cloud Peak Energy Inc. and its subsidiaries (the Company) at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

/s/PricewaterhouseCoopers LLP

Denver, Colorado

February 17, 2015

Table of Contents

CLOUD PEAK ENERGY INC.

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(in thousands, except per share data)

	Year Ended December 31, 2014	2013	2012
Revenue	$ 1,324,044	$ 1,396,097	$ 1,516,772
Costs and expenses			
Cost of product sold (exclusive of depreciation, depletion, and accretion, shown separately)	1,094,211	1,136,318	1,132,399
Depreciation and depletion	112,022	100,523	94,575
Accretion	15,136	15,342	13,189
Derivative financial instruments	(7,805)	(25,611)	(22,754)
Selling, general and administrative expenses	50,201	53,066	54,548
Other operating costs	2,739	4,077	2,949
Total costs and expenses	1,266,504	1,283,715	1,274,906
Gain on sale of Decker Mine interest	(74,262)		
Operating income	131,802	112,382	241,866
Other income (expense)			
Interest income	259	440	1,086
Interest expense	(77,160)	(41,665)	(36,327)
Tax agreement benefit (expense)	58,595	(10,515)	29,000
Other, net	(202)	2,423	(847)
Total other income (expense)	(18,508)	(49,317)	(7,088)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	113,294	63,065	234,778
Income tax benefit (expense)	(34,913)	(11,629)	(62,614)
Earnings from unconsolidated affiliates, net of tax	579	535	1,556
Net income (loss)	78,960	51,971	173,720
Other comprehensive income (loss)			
Postretirement medical plan amortization of prior service costs	989	1,775	1,575
Postretirement medical plan adjustment	(5,564)	10,824	(4,665)
Decker Mine pension adjustments		3,199	204
Write-off of prior service costs related to Decker Mine pension	3,183		
Income tax on postretirement medical plan and pension adjustments	372	(5,616)	1,039
Other comprehensive income (loss)	(1,020)	10,182	(1,847)
Total comprehensive income (loss)	$ 77,940	$ 62,153	$ 171,873
Income (loss) per common share			
Basic	$ 1.30	$ 0.86	$ 2.89
Diluted	$ 1.29	$ 0.85	$ 2.85
Weighted-average shares outstanding - basic	60,826	60,652	60,093
Weighted-average shares outstanding - diluted	61,295	61,161	60,927

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

Table of Contents

CLOUD PEAK ENERGY INC.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 168,745	$ 231,633
Investments in marketable securities		80,687
Accounts receivable	86,838	74,068
Due from related parties	227	742
Inventories, net	79,802	80,144
Deferred income taxes	21,670	18,326
Derivative financial instruments	17,111	26,420
Other assets	9,840	19,541
Total current assets	384,233	531,561
Noncurrent assets		
Property, plant and equipment, net	1,589,138	1,654,014
Port access contract rights	53,780	9,520
Goodwill	35,634	35,634
Deferred income taxes	56,468	91,361
Other assets	40,665	35,335
Total assets	$ 2,159,918	$ 2,357,425
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 52,035	$ 59,046
Royalties and production taxes	126,212	131,917
Accrued expenses	52,213	41,463
Current portion of tax agreement liability		13,504
Current portion of federal coal lease obligations	63,970	58,958
Other liabilities	1,632	2,513
Total current liabilities	296,062	307,401
Noncurrent liabilities		
Tax agreement liability, net of current portion		90,091
Senior notes	498,480	596,974
Federal coal lease obligations, net of current portion		63,970
Asset retirement obligations, net of current portion	216,241	246,081
Accumulated postretirement benefit obligation, net of current portion	50,276	38,862
Other liabilities	11,025	11,997
Total liabilities	1,072,084	1,355,376
Commitments and Contingencies (Note 18)		
Equity		
Common stock ($0.01 par value; 200,000 shares authorized; 61,434 and 61,296 shares issued and 61,022 and 60,896 outstanding at December 31, 2014 and December 31, 2013, respectively)	610	609
Treasury stock, at cost (432 shares and 400 shares at December 31, 2014 and December 31, 2013, respectively)	(6,243)	(5,667)

Additional paid-in capital		568,022		559,602
Retained earnings		536,744		457,784
Accumulated other comprehensive income (loss)		(11,299)		(10,279)
Total equity		1,087,834		1,002,049
Total liabilities and equity	$	2,159,918	$	2,357,425

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

Table of Contents

CLOUD PEAK ENERGY INC.

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands)

	Common Stock		Treasury Stock		Additional Paid-In	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Shares	Amount	Capital	Earnings	Income (Loss)	Total
Balances at December 31, 2011	60,923	$ 609		$	$ 536,301	$ 232,093	$ (18,614)	$ 750,389
Net income						173,720		173,720
Postemployment benefit adjustment, net of tax							(1,847)	(1,847)
Excess tax benefits related to equity-based compensation					1,201			1,201
Employee stock purchases	69	1			1,087			1,088
Stock compensation					11,796			11,796
Restricted stock issuance, net of forfeitures	119	1	97		(1)			
Employee common stock withheld to cover withholding taxes	(276)	(3)	276	(5,390)	3			(5,390)
Exercise of stock options	4				65			65
Balances at December 31, 2012	60,839	608	373	(5,390)	550,452	405,813	(20,461)	931,022
Net income						51,971		51,971
Postemployment benefit adjustment, net of tax							10,182	10,182
Excess tax benefits related to equity-based compensation					129			129
Employee stock purchases	68	1			968			969
Stock compensation					8,016			8,016
Restricted stock forfeitures, net of issuances	(11)		11					
Employee common stock withheld to cover withholding taxes	(16)		16	(277)				(277)
Exercise of stock options	16				37			37
Balances at December 31, 2013	60,896	609	400	(5,667)	559,602	457,784	(10,279)	1,002,049
Net income						78,960		78,960
Write-off of prior service costs related to Decker Mine pension, net of tax							2,038	2,038
Postemployment benefit adjustment, net of tax							(3,058)	(3,058)
Write-off of excess tax benefits related to equity-based compensation					(914)			(914)
Employee stock purchases	56	1			794			795
Stock compensation					7,966			7,966
Restricted stock issuance, net of forfeitures	16		3					
Employee common stock withheld to cover withholding taxes	(29)	(1)	29	(576)	(15)			(592)
Exercise of stock options	83	1			589			590
Balances at December 31, 2014	61,022	$ 610	432	$ (6,243)	$ 568,022	$ 536,744	$ (11,299)	$ 1,087,834

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

Table of Contents

CLOUD PEAK ENERGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income (loss)	$ 78,960	$ 51,971	$ 173,720
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and depletion	112,022	100,523	94,575
Accretion	15,136	15,342	13,189
Earnings from unconsolidated affiliates, net of tax	(579)	(535)	(1,556)
Distributions of income from unconsolidated affiliates	2,250	2,000	1,023
Deferred income taxes	31,921	13,860	42,210
Gain on sale of Decker Mine interest	(74,262)		
Tax agreement expense (benefit)	(58,595)	10,515	(29,000)
Equity-based compensation expense	7,966	8,016	11,796
Derivative mark-to-market (gains) losses	(7,805)	(25,611)	(22,754)
Cash received (paid) on derivative financial instrument settlements	24,672	12,976	11,244
Prepaid premiums on derivative financial instruments	(3,950)		
Non-cash interest expense related to early retirement of debt and refinancings	7,338		
Other	12,017	12,256	11,795
Changes in operating assets and liabilities:			
Accounts receivable	(12,825)	1,874	18,632
Inventories, net	(4,218)	1,709	(9,077)
Due to or from related parties	515	819	(1,090)
Other assets	14,588	(3,981)	(4,486)
Accounts payable and accrued expenses	(756)	3,540	(32,137)
Tax agreement liability	(45,000)	(23,459)	(25,097)
Asset retirement obligations	(1,221)	(1,075)	(5,632)
Net cash provided by (used in) operating activities	98,174	180,740	247,355
Investing activities			
Acquisition of Youngs Creek and CX Ranch coal and land assets			(300,377)
Purchases of property, plant and equipment	(18,719)	(46,780)	(53,550)
Cash paid for capitalized interest	(4,133)	(33,230)	(50,119)
Investments in marketable securities	(8,159)	(64,357)	(67,576)
Maturity and redemption of investments	88,845	64,011	62,463
Investment in port access contract rights	(39,260)	(2,160)	(7,360)
Investment in development projects	(3,522)	(4,087)	(29)
Return of restricted cash			71,244
Partnership escrow deposit			(4,470)
Return of partnership escrow		4,468	
Other	(1,687)	117	1,909
Net cash provided by (used in) investing activities	13,365	(82,018)	(347,865)
Financing activities			
Principal payments on federal coal leases	(58,958)	(63,191)	(102,198)
Issuance of senior notes	200,000		

Repayment of senior notes		(300,000)				
Payment of deferred financing costs		(14,755)		(1,039)		
Other		(714)		(550)		(3,841)
Net cash provided by (used in) financing activities		(174,427)		(64,780)		(106,039)
Net increase (decrease) in cash and cash equivalents		(62,888)		33,942		(206,549)
Cash and cash equivalents at beginning of period		231,633		197,691		404,240
Cash and cash equivalents at end of period	$	168,745	$	231,633	$	197,691
Supplemental cash flow disclosures						
Interest paid	$	50,330	$	69,478	$	84,201
Income taxes paid (refunded)	$	(6,874)	$	11,419	$	27,017
Supplemental noncash investing and financing activities						
Non-cash interest capitalized	$	69	$	3,994	$	7,845
Capital expenditures included in accounts payable	$	2,144	$	1,957	$	4,579
Assets acquired under capital leases	$	1,209	$	10,222	$	
Port access contract rights acquired in sale of Decker Mine interest	$	5,000	$		$	

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

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business

Cloud Peak Energy is one of the largest producers of coal in the United States of America (U.S.) and the Powder River Basin (PRB), based on our 2014 coal sales. We operate some of the safest mines in the coal industry. According to the most current Mine Safety and Health Administration (MSHA) data, we have one of the lowest employee all injury incident rates among the largest U.S. coal producing companies.

We currently operate solely in the PRB, the lowest cost region of the major coal producing regions in the U.S., where we operate three 100% owned surface coal mines, the Antelope Mine, the Cordero Rojo Mine and the Spring Creek Mine. We also have two major development projects, the Youngs Creek project and the Crow project. On September 12, 2014, we completed the sale of our 50% non-operating interest in Decker Coal Company (Decker Mine) to an affiliate of Ambre Energy North America, Inc. (Ambre Energy). For further information regarding this transaction, please see Note 4.

Our Antelope Mine and Cordero Rojo Mine are located in Wyoming and our Spring Creek Mine is located in Montana. Our mines produce subbituminous thermal coal with low sulfur content, and we sell our coal primarily to domestic and foreign electric utilities. We do not produce any metallurgical coal. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation and steam output. In 2014, the coal we produced generated approximately 4% of the electricity produced in the U.S.

In 2012, we acquired the Youngs Creek project. It is a permitted but undeveloped surface mine project in the Northern PRB region located 13 miles north of Sheridan, Wyoming, contiguous with the Wyoming-Montana state line. The Youngs Creek project is approximately seven miles south of our Spring Creek Mine and seven miles from the mainline railroad, and is near the Crow project. We have not yet been able to classify the Youngs Creek project mineral rights as proven and probable reserves as they remain subject to further exploration and evaluation. In 2013, we entered an option to lease agreement and a corresponding exploration agreement with the Crow Tribe of Indians. This coal project (Crow project) is located on the Crow Indian Reservation in southeast Montana. We are in the process of evaluating the development options for the Youngs Creek project and the Crow project and believe that their proximity to the Spring Creek Mine represents an opportunity to optimize our mine developments in the Northern PRB. For purposes of this report, the term Northern PRB refers to the area within the PRB that lies within Montana and the northern part of Sheridan County, Wyoming.

We continue to develop our sales of PRB coal and delivery services business into the Asian export market. In 2014, our logistics business was the largest U.S. exporter of thermal coal into South Korea. We continue to seek ways to increase our future export capacity through existing and proposed Pacific Northwest export terminals. In August 2014, we paid $37.0 million to secure additional committed capacity at the fully-utilized Westshore Terminals Limited Partnership port (Westshore), in British Columbia. As a result, we increased our long-term committed capacity from 2.8 million tons to 6.3 million tons initially and increasing to 7.2 million tons in 2019 and extended the term of our throughput agreement by two years through the end of 2024. In early 2015, as current international prices remain low, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons, thereby reducing our committed 2015 capacity at Westshore to 5.8 million tons. For further information on this transaction, see Note 9.

As part of the Decker Mine divestiture transaction, we were granted a throughput option for up to 7.7 million tons per year at the proposed Millennium Bulk Terminals coal export facility in Washington State. The proposed new coal export facility is currently in the permitting stage and is planned to be developed in two phases. Our option covers up to 3.3 million tons per year of capacity during the first phase of development and an additional 4.4 million tons per year once the second phase of development is reached. Our throughput capacity will have an initial term of 10 years, with four renewal options for five-year terms. Our option is exercisable following the successful completion of the ongoing permit process, which is currently in the EIS phase. The timing and outcome of the permit process are uncertain.

We also have a throughput option agreement with SSA Marine, which provides us with an option for up to 17.6 million tons of capacity per year through the planned dry bulk cargo Gateway Pacific Terminal at Cherry Point in Washington State. Our potential share of capacity will depend upon the ultimate capacity of the terminal and is subject to the terms of the option agreement. The terminal will accommodate cape size vessels. Our option is exercisable following the successful completion of the ongoing permit process, which is currently in the EIS phase. The timing and outcome of the permit process are uncertain.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For information regarding our revenue and long-lived assets by geographic area, as well as revenue from external customers, Adjusted EBITDA and total assets by segment, please see Note 24.

2. Basis of Presentation

Principles of Consolidation

We consolidate the accounts of entities in which we have a controlling financial interest under the voting control model. We accounted for our 50% non-operating interest in the Decker Mine, which was sold on September 12, 2014, using the proportionate consolidation method, whereby our share of Decker Mine s assets, liabilities, revenue and expenses were included in our consolidated financial statements through the date of the sale. Investments in other entities that we do not control but have the ability to exercise significant influence over the investee s operating and financial policies, are accounted for under the equity method. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the U.S. (U.S. GAAP). All intercompany balances and transactions have been eliminated in the consolidated financial statements.

Certain amounts have been reclassified to conform to current period presentations. Due to the tabular presentation of rounded amounts, certain tables reflect insignificant rounding differences.

3. Critical and Significant Accounting Policies

Use of Estimates

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting periods. Significant estimates in these consolidated financial statements include: assumptions about the amount and timing of future cash flows and related discount rates used in determining asset retirement obligations (AROs) and in testing long-lived assets and goodwill for impairment; the fair value of derivative financial instruments; the calculation of mineral reserves; equity-based compensation expense; workers compensation claims; reserves for contingencies and litigation; useful lives of long-lived assets; postretirement employee benefit obligations; the recognition and measurement of income tax benefits and related deferred tax asset valuation allowances; allowances for inventory obsolescence and net realizable value; and assumptions about the timing of future cash flows used in determining the tax agreement liability for periods before its termination in August 2014. Actual results could differ materially from those estimates.

Recently Issued Accounting Pronouncements

From time to time, the Financial Accounting Standards Board (FASB) or other standard setting bodies issue new accounting pronouncements. Updates to the FASB Accounting Standards Codification are communicated through issuance of an Accounting Standards Update (ASU). Unless otherwise discussed, we believe that the impact of recently issued guidance will not be material to our consolidated financial statements upon adoption.

Critical Accounting Policies

We consider certain accounting policies to be critical, as their application requires management s judgment about the effects of matters that are inherently uncertain. Following is a discussion of the accounting policies we consider critical to our consolidated financial statements.

Revenue Recognition

We recognize revenue from a sale when persuasive evidence of an arrangement exists, the price is determinable, the product has been delivered, title has transferred to the customer and collection of the sales price is reasonably assured.

Coal sales revenue include sales to customers of coal produced at our facilities and coal purchased from other companies. Coal sales are made to our customers under the terms of coal supply agreements, most of which have a term greater than one year. Under the typical terms of these coal supply agreements, title and risk of loss transfer to the customer

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

at the time the coal is shipped, which is the point at which revenue is recognized. Certain contracts provide for title and risk of loss transfer at the point of destination, in which case revenue is recognized when it arrives at its destination.

Coal sales contracts typically contain coal quality specifications. With coal quality specifications in place, the raw coal sold by us to the customer at the delivery point must be substantially free of magnetic material and other foreign material impurities, and crushed to a maximum size as set forth in the respective coal sales contract. Prior to billing the customer, price adjustments are made based on quality standards that are specified in the coal sales contract, such as Btu factor, moisture, ash, and sodium content and can result in either increases or decreases in the value of the coal shipped.

Transportation and related costs are included in cost of product sold, and amounts we bill to our customers for transportation are included in revenue.

In May 2014, FASB issued ASU 2014-09, Revenue from Contracts with Customers (ASU 2014-09) requiring entities to provide greater insight into both revenue that has been recognized and revenue that is expected to be recognized in the future from existing contracts. The new guidance is effective for interim and annual periods beginning after December 15, 2016. We are considering the impact of the adoption of ASU 2014-09 on our results of operations, financial condition and cash flows.

Asset Retirement Obligations and Remediation Costs

We recognize liabilities for AROs at fair value where we have legal obligations associated with the retirement of long-lived assets. We recognize AROs at the time the obligations are incurred. Our AROs generally are incurred when a mine site is disturbed by mining activities and as the extent of disturbance increases. AROs reflect costs associated with legally required mine reclamation and closure activities, including earthwork, vegetation, and demolition and are estimated based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are adjusted for estimated inflation and discounted at credit-adjusted, risk-free rates to arrive at a present value of estimated future reclamation costs. The ARO amount is capitalized as part of the related mining property upon initial recognition and is included in depreciation and depletion expense using the units-of-production method based on proven and probable reserves. As changes in estimates occur (such as changes in estimated costs or timing of reclamation activities resulting from mine plan revisions or new LBAs), the ARO liability and related asset are adjusted to reflect the updated estimates. Increases in ARO liabilities resulting from the passage of time are recognized as accretion expense. Other costs related to environmental remediation are charged to expense as incurred. If a reduction of the ARO exceeds the carrying amount of the related asset retirement cost, the adjustment is recorded as a reduction of depletion expense.

Tax Agreement Liability

In August 2014, we entered into an acceleration and release agreement with Rio Tinto whereby we agreed to pay $45.0 million to Rio Tinto to terminate the TRA. This payment settled all existing and future liabilities that were or would have been owed under the TRA.

The actual amounts payable under the TRA were determined and paid annually, after we filed the income tax returns for the prior year. The annual payments were determined based on the difference between (i) CPE Inc. s actual income tax liability for the prior year, which reflects the effects of the increase in tax basis that resulted from its acquisition of interests in CPE Resources, and (ii) a hypothetical calculation of CPE Inc. s tax liability that assumed no such increase in tax basis. The required annual payments were equal to 85% of the tax savings actually realized as a result of the tax basis increase. Our estimate of the tax agreement liability was based on forecasts of our future income tax payments, with and without the tax basis increase, over the anticipated life of our mining operations and reclamation activities, assuming no additional coal reserves were acquired. The assumptions used in our forecasts were consistent with assumptions used in determining the valuation allowance for our deferred tax assets and in other contemporaneous accounting measurements, such as our annual test of goodwill impairment. We revised our estimated tax agreement liability annually in conjunction with our annual life-of-mine planning process, which typically takes place in the third quarter, or more frequently when there are significant changes in circumstances, such as the acquisition of additional coal reserves. Changes in our estimated tax agreement liability were recognized in Other income (expense) in our consolidated statement of operations. See Note 11 for more information about the Tax Agreement Liability.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Significant Accounting Policies

Cash and Cash Equivalents

We consider all highly-liquid investments with an original maturity of three months or less to be cash equivalents. Money market funds that meet all qualifying criteria for a money market fund under the Investment Company Act of 1940 are considered to be cash equivalents.

Investments in Marketable Securities

Investments in marketable securities consist of highly-liquid, investment grade or better, instruments. Investments in marketable securities are recognized on the balance sheet at fair value. Changes in the fair value are recorded in Other income (expense) on the consolidated statements of operations each period using mark-to-market accounting. During the year ended December 31, 2014, we redeemed our investments in marketable securities and used the proceeds to pay down a portion of the principal on our senior notes. See Note 12 for further information on this transaction.

Allowance for Doubtful Accounts Receivable

We determine an allowance for doubtful accounts based on the aging of accounts receivable, historical experience, and management judgment. We write off accounts receivable against the allowance when we determine a balance is uncollectible and we no longer continue to actively pursue collection of the receivable. Based on our assessment of the above criteria, there was no allowance for doubtful accounts at December 31, 2014 and 2013.

Inventories, Net

Materials and Supplies

We state materials and supplies at average cost. We establish allowances for excess or obsolete materials and supplies inventory based on prior experience and estimates of future usage.

Coal Inventory

We state our coal inventory, which consists of coal stockpiles that may be sold in their current condition or may be further processed prior to shipment to a customer, at the lower of cost or net realizable value. Net realizable value represents the estimated future sales price based on spot coal prices and prices under long-term contracts, less the estimated costs to complete production and bring the product to sale. The cost of coal inventory reflects mining costs incurred up to the point of stockpiling the coal and includes labor, supplies, equipment, applicable operating overhead, and depreciation, depletion, and amortization related to mining operations.

Prepaid Freight

Our logistics business incurs freight and related charges moving coal from the Spring Creek Mine to the port, as well as terminal handling charges and demurrage. These costs are included in Other current assets on the consolidated balance sheets until such time as the revenue is recognized on the associated coal.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Property, Plant and Equipment

Plant and Equipment

We state plant and equipment at cost, less accumulated depreciation. Plant and equipment used in mining operations that are expected to remain in service for the life of the related mine are depreciated using the units-of-production method based on proven and probable reserves. Depreciation of other plant and equipment is computed using the straight-line method over the following estimated useful lives:

Buildings and improvements	5 to 25 years
Machinery and equipment	3 to 20 years
Furniture and fixtures	3 years

Mineral Rights

Mineral rights include both proven and probable reserves and non-reserve coal deposits. We state our mineral rights at cost, less accumulated depletion. We compute depletion of mineral rights using the units-of-production method based on proven and probable reserves. Non-reserve coal deposits are not depleted until they qualify as proven and probable reserves and the mining begins. Mineral rights are included in property, plant and equipment, net.

Upon the award date of federal coal leases, pursuant to which payments are required to be paid in equal annual installments, we recognize an asset for the related mineral rights in property, plant and equipment and a corresponding liability for our future payment obligations in current and non-current liabilities. The amount recognized as an asset is the sum of the initial installment due at the effective date of the lease and the amount recognized in current and non-current liabilities, which reflects the present value of the remaining installments. We determine the present value of the remaining installments using an estimate of the credit-adjusted, risk-free rates that reflects our credit rating. Interest is recognized over the term of the lease based on the imputed interest rate that was used to determine the initial current and non-current liabilities amount on the effective date. Such interest may be capitalized while activities are in progress to prepare the acquired coal reserves for mining.

Imputed interest on federal coal leases for the years ended December 31 was as follows (in thousands):

	2014	2013	2012
Imputed interest	$ 8,062	$ 13,212	$ 20,406

Land and Surface Rights

We purchase surface lands in order to gain access to our mineral rights. Land is typically acquired for amounts greater than its fair value as a result of the value of the coal beneath it. The value of the land is determined based on published agricultural values and is not depleted. The value of the surface rights is the amount paid in excess of the published agricultural value and is depleted over the useful life of the respective land parcel. Both land and surface rights are included in land and land improvements in property, plant and equipment, net.

Capitalization of Interest

We capitalize interest costs on accumulated expenditures incurred in preparing capital projects for their intended use.

Mine Development Costs

We capitalize costs of developing new mines where proven and probable reserves exist. We amortize mine development costs using the units-of-production method based on proven and probable reserves that are associated with the property being developed. Costs may include construction permits and licenses; mine design; construction of access roads, slopes and main entries; and removing overburden and waste materials to access the coal ore body in a new pit prior to the production phase, which commences when saleable coal, beyond a de minimis amount, is produced. Where multiple pits exist at a mining operation, overburden removal costs are capitalized if such costs are for the development of a new area that

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

is separate and distinct from the existing production phase mines. Overburden removal costs that relate to the enlargement of an existing pit are expensed as incurred. Overburden removal costs incurred during the production phase are included as a cost of inventory to be recognized in cost of product sold in the same period as the revenue from the sale of inventory. Additionally, mine development costs include the costs associated with AROs. Mine development costs are included in land, improvements, and mineral rights in property, plant and equipment, net.

Repairs and Maintenance

We capitalize costs associated with major renewals and improvements. Expenditures to replace or completely rebuild major components of major equipment, which are required at predictable intervals to maintain asset life or performance, are capitalized. These major components are capitalized separately from the major equipment and depreciated according to their own estimated useful life, rather than the estimated useful life of the major equipment. All other costs of repairs and maintenance are charged to expense as incurred.

Exploration Costs

We expense all direct costs incurred in identifying new resources and in converting resources to reserves at development and production stage projects. Exploration costs are included in cost of product sold and consisted of the following for the years ended December 31 (in thousands):

	2014	**2013**	**2012**
Exploration Costs	$ 3,101	$ 2,409	$ 1,671

Impairment

We evaluate the recoverability of our long-lived assets when events or changes in circumstances indicate that the carrying amount of property, plant and equipment may not be recovered over its remaining service life. An asset impairment charge is recognized when the sum of estimated future cash flows associated with the operation and disposal of the asset, on an undiscounted basis, is less than the carrying amount of the asset. An impairment charge is measured as the amount by which the carrying amount of the asset exceeds its fair value. Fair value is measured using discounted cash flows based on estimates of coal reserves, coal prices, operating expenses, and capital costs or by reference to observable comparable transaction or replacement cost data. No impairments have been recognized for the years ended December 31, 2014, 2013, and 2012.

Goodwill

We assess the carrying amount of goodwill for impairment annually as of the beginning of the fourth quarter, or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We assess goodwill for possible impairment using a two-step method in which we compare the carrying amount of each reporting unit to its fair value. If the carrying amount of a reporting unit exceeds its fair value, we perform an analysis to determine the fair values of the assets and liabilities of the reporting unit to determine whether the implied goodwill of that reporting unit has been impaired. We determine the fair value of our reporting units utilizing estimated future discounted cash flows based on estimates of coal volumes, coal prices, and operating and equipment costs, consistent with assumptions that we believe marketplace participants would use in their estimates of fair value. No impairments have been recognized for the years ended December 31, 2014, 2013, and 2012. There have been no changes in the carrying amount of our goodwill, and there are no accumulated impairment losses. The entire carrying amount of goodwill is included in our Owned and Operated Mines segment.

Derivative Financial Instruments

We are exposed to various types of risk in the normal course of business, including fluctuations in the price at which we are able to sell our coal in the future and the price we are able to purchase diesel fuel used in our operations. We seek to mitigate some of the volatility of these fluctuations by using derivative financial instruments. We recognize all derivative financial instruments as assets or liabilities at their respective fair value in the consolidated balance sheets. All derivative financial instruments are included in current assets or liabilities as we have the ability to settle the positions at any time. Gains or losses from changes in the fair value of derivative financial instruments are recognized immediately in the

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

consolidated statements of operations in operating income. Assets and liabilities with the same counterparty, where right of offset is allowed, are recorded on a net basis on the balance sheets.

Our derivative financial instruments do not qualify for hedge accounting; therefore, changes in the fair value of the derivative financial instruments are recorded in Derivative financial instruments on the consolidated statements of operations each period using mark-to-market accounting.

Fair Value of Financial Instruments

Our financial instruments included cash equivalents, accounts receivable, amounts due from related parties, accounts payable, and certain current liabilities. Due to the short-term nature of these instruments, we believe that their carrying amounts approximated fair value.

Certain cash equivalents, investments in marketable securities, and derivative financial instruments are reported on our balance sheet at fair value. We categorize assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. See Notes 7 and 6.

Pensions and Other Postretirement Benefits

Our employees participate in defined contribution retirement plans, which require us to make contributions based on a percentage of compensation or to match employee contributions, subject to limitations. We recognize compensation expense for our required contributions as incurred.

Our postretirement medical plan provides retiree medical benefits for our employees. We account for postretirement benefits other than pensions by accruing the costs of benefits to be provided over the employees period of active service. These costs are determined on an actuarial basis.

Income Taxes

We account for income taxes using a balance sheet approach in accordance with U.S. GAAP. 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 expected 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. In determining the appropriate valuation allowance, we consider projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and our overall deferred tax position. We recognize the benefit of uncertain tax positions at the greatest amount that is determined to be more likely than not of being realized. Interest and penalties related to income tax matters are included in income tax expense in the consolidated statements of operations.

During the year ended December 31, 2013, the Department of the Treasury finalized guidance regarding the deduction and capitalization of expenditures related to tangible property. The regulations became effective on January 1, 2014 with optional early adoption. Adopting these regulations did not have a material impact on our financial position or results of operations.

Non-Income Based Taxes and Royalties

We are subject to certain production, severance, and extraction taxes and royalties that are charged based on a percentage of coal production or coal sales. The taxes and royalties are paid to federal, state and local governments or to private parties based on legally established methodologies, rates, and timeframes.

Equity-Based Compensation

We measure the cost of equity-based employee compensation based on the fair value of the award and recognize that cost over the period during which the recipient is required to provide services in exchange for the award, typically the vesting period. For equity-based awards, compensation cost is measured based on grant-date fair value of the award. The fair value of certain equity-based awards is estimated using either the Black-Scholes option valuation model or a Monte Carlo simulation. Our policy is to issue new shares upon the exercise of stock options or conversion of stock units.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Earnings per Share

We compute basic earnings per share by dividing net income by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed using the weighted-average number of shares of common and potential dilutive common stock outstanding during the period. We apply the treasury stock method to determine potential dilutive common shares related to our stock options and non-vested stock awards.

Accrued Liabilities

Contingent Liabilities

We account for contingent liabilities related to litigation, claims, and assessments based on the specific facts and circumstances and our experience with similar matters. We record our best estimate of a loss when the loss is considered probable and the amount of loss is reasonably estimable. When a loss is probable and there is a range of the estimated loss with no best estimate in the range, we record our estimate of the minimum liability. As additional information becomes available, we revise our estimates as appropriate.

Workers Compensation

For our employees in Wyoming, workers compensation insurance is provided through a state-funded program. We contribute to this program by applying the rate assessed by the state to gross payroll for the applicable employees, which is adjusted prospectively based on our workers compensation historical incident rating. In exchange for a reduced rate, we assume liability for the first $100,000 of each claim. For our employees in Colorado and Montana, workers compensation insurance is provided under a large-deductible workers compensation program, which provides full coverage for any workers compensation losses in excess of $250,000 per incident. Our liability related to the large deductibles is recorded on the balance sheet using a fully developed actuarial estimate.

During 2012, we were approved by the Department of Labor as a self-insured employer for federal black lung liabilities. We fund these liabilities through two black lung trusts, but would be required to pay any claims in excess of the amounts in the trusts.

Discontinued Operations

In April 2014, FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) (ASU 2014-08), which changes the criteria for reporting discontinued operations and requires additional disclosures about discontinued operations. The standard requires that we report as a discontinued operation only those disposals that represent a strategic shift and have a major effect on our operations and financial results. ASU 2014-08 is effective prospectively for new disposals that occur within annual periods beginning on or after December 15, 2014 with early adoption permitted. We elected to adopt ASU 2014-08 during the three months ended September 30, 2014 and have applied the new guidance to the sale of our 50% non-operating interest in the Decker Mine described in Note 4. The sale of our ownership interest does not represent a strategic shift that has a major impact on our operations or financial results; therefore, the transaction is being reported as a disposal of a significant component and not as a discontinued operation.

4. Sale of Decker Mine Interest

On September 12, 2014, we completed the sale of our 50% non-operating interest in the Decker Mine to Ambre Energy. Under the terms of the agreement, Ambre Energy acquired our 50% interest in the Decker Mine and related assets and assumed all reclamation and other liabilities, giving Ambre Energy 100% ownership of the Decker Mine. Ambre Energy also fully replaced our $66.7 million in outstanding reclamation and lease bonds relating to our 50% interest in the Decker Mine s reclamation and lease liabilities. As we no longer have any ownership interest and all of the Decker Mine liabilities have been assumed by Ambre Energy, Ambre Energy is now fully responsible for reclamation at the end of the Decker Mine s life. As a result, we released the related $72.2 million of asset retirement obligation.

In addition, an affiliate of Ambre Energy granted us an option for up to 7.7 million tons per year of its throughput capacity at the proposed Millennium Bulk Terminals coal export facility. The proposed new coal export facility at Millennium Bulk Terminals in Washington State, which is owned 62% by an affiliate of Ambre Energy and 38% by Arch Coal, is currently in the permitting stage. It is planned to be developed in two phases: the first phase is planned to have

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

capacity of 27.6 million tons per year with the second phase taking annual capacity to 48.5 million tons. Our option covers up to 3.3 million tons per year of Ambre Energy s share of the first phase and 4.4 million tons per year of its share of the second phase. Our throughput capacity will have an initial term of 10 years, with four renewal options for five-year terms. Our option is exercisable following the successful completion of the ongoing permit process for the terminal, the timing and outcome of which are uncertain. We valued the option using a discounted cash flow analysis based on comparable agreements, the terms of the agreement and general market data.

As a result of this agreement, we recognized a gain on sale of the Decker Mine interest of $74.3 million as follows (in thousands):

Net cash surrendered	$	(207)
ARO liability released		72,175
Millennium Bulk Terminals option		5,000
Write-off of prior service costs related to the Decker Mine pension		(3,183)
Net other (assets) liabilities		820
Other		(343)
Pre-tax gain on sale of Decker Mine interest	$	74,262

We reported the results of our 50% interest in the Decker Mine in our Corporate and Other segment. Results of operations, up to the date of sale, for the Decker Mine included in the consolidated statements of operations and comprehensive income consist of the following (in thousands):

	Year Ended December 31,					
		2014		2013		2012
Decker Mine						
Revenues	$	15,653	$	21,474	$	22,176
Costs and expenses		19,475		21,772		35,351
Operating income (loss)		(3,823)		(298)		(13,176)
Other income (expense)		(41)		(58)		(62)
Income (loss) before income tax provision	$	(3,863)	$	(356)	$	(13,238)

The table below summarizes the assets and the liabilities of the Decker Mine prior to the completion of the sale of our 50% ownership interest (in thousands):

		September 12, 2014		December 31, 2013
ASSETS				
Current Assets				
Cash and cash equivalents	$	207	$	4,143
Accounts receivable, net		3,326		2,130

Inventories, net		4,552		3,744
Other		18		97
Total current assets		8,103		10,114
Property, plant and equipment, net		15		34
Total assets	$	8,118	$	10,148
LIABILITIES				
Current Liabilities				
Accounts payable	$	1,211	$	1,186
Royalties and production taxes		2,387		2,758
Accrued expenses		693		480
Other current liabilities		966		966
Total current liabilities		5,257		5,390
Asset retirement obligations		72,175		70,806
Other liabilities		3,474		3,142
Total liabilities	$	80,906	$	79,338

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Inventories

Inventories, net, consisted of the following at December 31 (in thousands):

	2014		2013	
Materials and supplies	$	77,736	$	77,748
Less: Obsolescence allowance		(1,102)		(1,011)
Material and supplies, net		76,634		76,737
Coal inventory		3,168		3,406
Inventories, net	$	79,802	$	80,144

6. Fair Value of Financial Instruments

We use a three-level fair value hierarchy that categorizes assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. 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. Our Level 1 assets currently include money market funds.

- 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. Our Level 2 assets and liabilities currently include investments in marketable securities, primarily asset-backed securities, and derivative financial instruments 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. We have no Level 3 investments as of December 31, 2014 or 2013.

The tables below set forth, by level, our financial assets and liabilities that are recorded at fair value in the accompanying condensed consolidated balance sheets (in thousands):

Description		Fair Value at December 31, 2014 Level 1		Level 2		Total
Assets						
Money market funds(1)	$	98,789	$		$	98,789
Derivative financial instruments	$		$	17,111	$	17,111
Liabilities						
Derivative financial instruments	$		$	3,608	$	3,608

Description		Fair Value at December 31, 2013 Level 1		Level 2		Total
Assets						
Money market funds(1)	$	140,438	$		$	140,438
Derivative financial instruments	$		$	26,420	$	26,420
Investments in marketable securities	$		$	80,687	$	80,687

(1) Included in cash and cash equivalents in the consolidated balance sheets along with $70.0 million and $91.2 million of demand deposits at December 31, 2014 and 2013, respectively.

We did not have any transfers between levels during the years ended December 31, 2014 and 2013. Our policy is to value all transfers between levels using the beginning of period valuation.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. Derivative Financial Instruments

Coal Contracts

We use international coal forward contracts linked to forward Newcastle coal prices to help manage our exposure to variability in international coal prices. We use domestic coal futures contracts referenced to the 8800 Btu coal price sold from the PRB, as quoted on the Chicago Mercantile Exchange (CME), to help manage our exposure to market changes in domestic coal prices. At December 31, 2014, we held positions that are expected to settle in the following years (in thousands):

	2015	2016	Total
International Coal Forward Contracts			
Notional amount (tons)	430	132	562
Net asset position	$ 14,848	$ 5,884	$ 20,732
Domestic Coal Futures Contracts			
Notional amount (tons)	1,980	120	2,100

Amounts due to us or to the CME as a result of changes in the market price of our open domestic coal futures contracts and to fulfill margin requirements are received or paid through our brokerage bank on a daily basis; therefore, there is no asset or liability on the consolidated balance sheets.

WTI Derivatives

We use derivative financial instruments, such as collars and call options, to help manage our exposure to market changes in diesel fuel prices. The derivatives are indexed to the West Texas Intermediate (WTI) crude oil price as quoted on the New York Mercantile Exchange. As such, the nature of the derivatives does not directly offset market changes to our diesel costs.

Under a collar agreement, we pay the difference between the monthly average index price and a floor price, or put option, if the index price is below the floor, and we receive the difference between the ceiling price, or call option, and the monthly average index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices. While we would not receive the full benefit of price decreases beyond the collars, the collars mitigate the risk of crude oil price increases and thereby increased diesel costs that would otherwise have a negative impact on our cash flow.

During the year ended December 31, 2014, we settled the ceilings of our collar arrangements by either closing out the positions or entering into offsetting put positions and entered into new call options by paying a premium of $4 million. We left the put options in place. At December 31, 2014, we held the following WTI derivative financial instruments:

	Floor			Ceiling		
Settlement Period	**Notional Amount (barrels)**		**Weighted-Average per Barrel**	**Notional Amount (barrels)**		**Weighted-Average per Barrel**
2015 collar positions (1)	396	$	71.59	396	$	80.00
2015 cap positions (2)				296		80.00
Offsetting previous cap	132		106.50	132		106.50
Total	528	$	80.32	824	$	84.24

(1) Represents 75% of expected diesel consumption for the first, second, and third quarters of 2015.

(2) Represents 25% of expected diesel consumption for the first, second and third quarters of 2015 and 100% of expected diesel consumption for the fourth quarter of 2015.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Offsetting and Balance Sheet Presentation

	December 31, 2014					
	Gross Amounts of Recognized		Gross Amounts Offset in the Consolidated Balance Sheet		Net Amounts Presented in the Consolidated Balance Sheet	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
International coal forward contracts	$ 20,861	$ (129)	$ (129)	$ 129	$ 20,732	$
WTI derivative financial instruments		(7,228)	(3,620)	3,620	(3,620)	(3,608)
Total	$ 20,861	$ (7,357)	$ (3,749)	$ 3,749	$ 17,111	$ (3,608)

	December 31, 2013					
	Gross Amounts of Recognized		Gross Amounts Offset in the Consolidated Balance Sheet		Net Amounts Presented in the Consolidated Balance Sheet	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
International coal forward contracts	$ 26,712	$ (349)	$ (349)	$ 349	$ 26,362	$
WTI derivative financial instruments	58				58	
Total	$ 26,770	$ (349)	$ (349)	$ 349	$ 26,420	$

Net amounts of international coal forward contracts and WTI derivative assets are included in the Derivative financial instruments line and net amounts of WTI derivative liabilities are included in Accrued expenses in the consolidated balance sheets. There were no cash collateral requirements at December 31, 2014 or 2013.

Derivative Gains and Losses

Derivative mark-to-market (gains) and losses recognized in the consolidated statement of operations and comprehensive income were as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
International coal forward contracts	$ (21,369)	$ (25,952)	$ (22,616)
Domestic coal futures contracts	1,701	260	
WTI derivative financial instruments	11,863	81	(138)
Total	$ (7,805)	$ (25,611)	$ (22,754)

The mark-to-market loss on the WTI derivative financial instruments is related to the recent decline in oil prices to an average forward price of $54.84 per barrel and includes the premium paid of $4.0 million. See Note 6 for a discussion related to the fair value of derivative financial instruments.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

8. Property, Plant and Equipment

Property, plant and equipment, net consisted of the following at December 31 (in thousands):

	2014	2013
Land, surface rights, and mineral rights(1)	$ 1,679,133	$ 1,718,481
Mining equipment	887,695	880,012
Construction in progress	13,560	13,804
Other equipment	38,958	67,402
Buildings and improvements	72,077	71,637
Total	2,691,422	2,751,337
Less: accumulated depreciation and depletion	(1,102,284)	(1,097,322)
Property, plant and equipment, net	$ 1,589,138	$ 1,654,014

(1) Includes mineral rights of $683.8 million and $735.6 million at December 31, 2014 and 2013, respectively, attributable to areas where we were not yet engaged in mining operations and, therefore, the mineral rights were not being depleted.

During the years ended December 31, interest costs capitalized on mine development and construction projects totaled the following (in thousands):

	2014	2013	2012
Interest costs capitalized	$ 208	$ 29,378	$ 41,975

9. Port Access Contract Rights

In August 2014, we paid $37.0 million to Coal Valley Resources, Inc. (CVRI), a recently acquired unit of Westmoreland Coal Company, to terminate its throughput agreement with Westshore. In a related transaction, we amended our agreement with Westshore to increase our committed capacity from 2.8 million tons to 6.3 million tons initially and increasing to 7.2 million tons in 2019 and extend the term of our throughput agreement from the end of 2022 through the end of 2024. We have capitalized the $37.0 million payment as an intangible asset. In early 2015, as current international prices remain low, we have worked with our logistics partners to reduce expected second quarter exports by approximately 550,000 tons, thereby reducing our committed 2015 capacity at Westshore to 5.8 million tons.

Other port access contract rights include $11.7 million related to the SSA Marine throughput option agreement and $5.0 million for the Millennium Bulk Terminals throughput option. See below and Note 1 for further information on these agreements.

	Cloud Peak Energy s Annual Throughput (million tons)	Net Asset (in millions)	Term
Existing Ports			
Westshore	6.3 - 7.2 (1)	$ 37.1	2015 - 2024
Proposed Ports			
SSA Marine s Gateway Pacific Terminal at Cherry Point	Up to 17.6	$ 11.7	10 Years (2)
Millennium Bulk Terminals	Up to 7.7	$ 5.0	10 Years (3)

(1) In early 2015, we reached an agreement to reduce our committed 2015 capacity to 5.8 million tons.

(2) From date developer certifies port is available to Cloud Peak Energy.

(3) From date of first Cloud Peak Energy shipment.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Port access contract rights, net consisted of the following (in thousands):

	December 31, 2014	December 31, 2013
Port access contract rights	$ 53,780	$ 9,520
Less: Accumulated amortization		
Port access contract rights, net	$ 53,780	$ 9,520

We will amortize the costs on a straight line basis over the performance period of the contracts. As none of those periods have yet begun, there was no amortization expense for the year ended December 31, 2014. Future amortization expense related to the port access contract rights is currently expected to be $3.7 million per year beginning January 1, 2015 through 2019 with additional amounts in later years.

10. Equity Method Investments

Equity method investments include our 50% equity investment in Venture Fuels Partnership, a coal marketing company, and are included in other noncurrent assets and have a carrying amount of the following at December 31 (in thousands):

	2014	2013
Equity method investments	$ 5,873	$ 7,203

During the years ended December 31, 2014, 2013, and 2012, we recognized $0.9 million, $0.8 million, and $2.4 million in pre-tax income and received $2.3 million, $2.0 million, and $1.0 million in distributions, respectively, related to our investment in Venture Fuels Partnership.

11. Tax Agreement Liability

In connection with the 2009 initial public offering (IPO), we entered into the TRA with Rio Tinto, our former parent, and recognized a liability for the undiscounted amounts that we estimated would be paid to Rio Tinto under this agreement. The amounts paid were determined based on an annual calculation of future income tax savings that we actually realized as a result of the tax basis increase that resulted from the 2009 IPO and 2010 Secondary Offering transactions. Generally, we retained 15% of the realized tax savings generated from the tax basis step-up and Rio Tinto was entitled to the remaining 85%.

In August 2014, we entered into an acceleration and release agreement with Rio Tinto whereby we agreed to pay $45.0 million to Rio Tinto to terminate the TRA. This payment settles all existing and future liabilities that were or would have been owed under the TRA. At the date of signing, we carried an undiscounted liability of $103.6 million in respect of our estimated future obligations under the TRA and anticipated making cash payments of approximately $14 million each year in 2014 and 2015 and additional payments in subsequent years.

The termination of the TRA resulted in a non-cash gain during the third quarter of 2014 of $58.6 million before tax and $37.1 million after adjustments to the associated deferred tax assets. We continue to retain the deferred tax assets related to the step up in tax basis as a result of the 2009 IPO and 2010 Secondary Offering transactions. As such, we now expect to benefit from 100% of the increased tax depreciation.

12. Senior Notes

On March 11, 2014, Cloud Peak Energy Resources LLC and Cloud Peak Energy Finance Corp. (collectively, the Issuers) issued $200 million aggregate principal amount of 6.375% Senior Notes due 2024 (2024 Notes) at an issue price of 100% of the face amount. We used the net proceeds to fund a portion of the Issuers tender offer and consent solicitation for the Issuers previously existing 8.25% Senior Notes due 2017 (2017 Notes), as discussed below. There are no mandatory redemption or sinking fund payments for the 2024 Notes and interest payments are due semi-annually on March 15 and September 15, beginning on September 15, 2014. Subject to certain limitations, we may redeem some or all of the 2024 Notes by paying specified redemption prices in excess of their principal amount, plus accrued and unpaid interest, if any, prior to March 15, 2022, or by paying their principal amount thereafter, plus accrued and unpaid interest, if any.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Debt issuance costs of $4.9 million, including underwriting discounts and commissions, were incurred in connection with the issuance of the 2024 Notes. These costs have been deferred and are being amortized to interest expense over the term of the 2024 Notes using the straight-line method which approximates the effective interest method.

The senior notes are jointly and severally guaranteed by CPE Inc. and all of our existing and future restricted subsidiaries that guarantee our debt under our credit facility. See Note 14. Substantially all of our current consolidated subsidiaries, excluding Cloud Peak Energy Receivables LLC, are considered to be restricted subsidiaries and guarantee the senior notes.

The indentures governing the senior notes, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness and issue preferred equity; pay dividends or distributions; repurchase equity or repay subordinated indebtedness; make investments or certain other restricted payments; create liens; sell assets; enter into agreements that restrict dividends, distributions, or other payments from restricted subsidiaries; enter into transactions with affiliates; and consolidate, merge, or transfer all or substantially all of their assets and the assets of their restricted subsidiaries on a combined basis.

Upon the occurrence of certain transactions constituting a change in control as defined in the indentures, holders of our senior notes could require us to repurchase all outstanding notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

In the first quarter of 2014, we used the proceeds from the 2024 Notes, together with cash on hand, to repurchase and redeem $300 million aggregate principal amount of the 2017 Notes. We recognized a loss on early retirement of debt of $19.3 million, which was comprised of $13.8 million related to the premium paid in excess of par, $5.1 million related to the write-off of deferred financing costs and original issue discount, and $0.4 million in related expenses. The loss is classified in Interest expense in consolidated statement of operations.

Senior notes consisted of the following at December 31 (in thousands):

	2014			2013		
	Principal	**Carrying Value**	**Fair Value (1)**	**Principal**	**Carrying Value**	**Fair Value (1)**
8.25% senior notes due 2017, net of unamortized discount	$	$	$	$ 300,000	$ 298,727	$ 313,125
8.50% senior notes due 2019, net of unamortized discount	300,000	298,480	315,000	300,000	298,248	325,500
	200,000	200,000	189,500			

6.375% senior notes due 2024												
Total senior notes	$	500,000	$	498,480	$	504,500	$	600,000	$	596,974	$	638,625

(1) The fair value of the senior notes was based on observable market inputs, which are considered Level 2 in the fair value hierarchy.

Debt issuance costs of approximately $12 million were incurred in connection with the issuance of the 2019 Notes and 2024 Notes. These costs were deferred and are being amortized to interest expense over the respective terms of the senior notes using the effective interest method. Unamortized debt issuance costs included in noncurrent other assets totaled the following at December 31 (in thousands):

		2014		**2013**
Unamortized debt issuance costs	$	8,765	$	8,922

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Future Maturities

Aggregate future maturities of long-term debt as of December 31, 2014 are as follows (in thousands):

2019	$	300,000
2024		200,000
Less discount on senior notes		(1,520)
Total long-term debt	$	498,480

13. Federal Coal Lease Obligations

At December 31, federal coal lease obligations comprise (in thousands):

		2014		2013
Federal coal lease obligations, current	$	63,970	$	58,958
Federal coal lease obligations, noncurrent				63,970
Total federal coal lease obligations	$	63,970	$	122,928

Our federal coal lease obligations, as reflected in the consolidated balance sheets, consist of discounted obligations payable to the Bureau of Land Management of the U.S. Department of the Interior (the BLM) discounted at an imputed interest rate. Imputed interest is included in accrued expenses.

As of December 31, we have the following federal coal lease payments, (dollars in thousands):

				2014				2013			
Payment Dates		Annual Payment	Imputed Interest Rate		Carrying Value		Fair Value (1)		Carrying Value		Fair Value (1)
July 1, 2011 2015	$	59,545	8.50%	$	54,880	$	58,976	$	105,460	$	116,664
September 1, 2011 2015	$	9,862	8.50%		9,090		9,736		17,467		19,255
				$	63,970	$	68,712	$	122,928	$	135,919

(1) The fair value of estimates for federal coal lease obligations was determined by discounting the remaining lease payments using the then current estimate of the credit-adjusted, risk-free rate based on our then current credit rating, which is considered Level 2 in the fair value hierarchy.

Future payments on federal coal leases are as follows (in thousands):

Year Ended December 31,		
2015		69,407
Total		69,407
Less: imputed interest		5,437
Total principal payments		63,970
Less: current portion		63,970
Long-term federal coal leases payable	$	

14. Other Obligations

Capital Equipment Lease Obligations

During the year ended December 31, 2014, we entered into capital leases on equipment under various lease schedules, which are subject to the master lease agreement, and are pre-payable at our option. Interest on the leases is based on the one-month LIBOR plus 1.95% for a current rate of 2.11% as of December 31, 2014. The gross value of property, plant and equipment under capital leases was $11.4 million as of December 31, 2014 and related primarily to mining

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

equipment. The accumulated depreciation for these items was $1.9 million at December 31, 2014, and changes thereto have been included in depreciation, depletion and amortization in the consolidated statements of operations. Due to the variable nature of the imputed interest, fair value is equal to carrying value.

Future payments on capital equipment lease obligations are as follows (in thousands):

Year Ended December 31,		
2015	$	1,808
2016		1,774
2017		1,739
2018		1,705
2019		1,670
Thereafter		879
Total		9,574
Less: interest		537
Total principal payments		9,037
Less: current portion		1,633
Capital equipment lease obligations, net of current portion	$	7,404

Accounts Receivable Securitization

On February 11, 2013, we executed an Accounts Receivable Securitization Facility (A/R Securitization Program) with a committed capacity of up to $75.0 million, which was due to expire on February 11, 2015. On January 23, 2015, we entered into an agreement extending the term of the A/R Securitization Program until January 23, 2018. All other terms of the program have remained substantially the same. Certain of our subsidiaries are parties to the A/R Securitization Program. In January 2013, we formed Cloud Peak Energy Receivables LLC (the SPE), a special purpose, bankruptcy-remote 100% owned subsidiary, to purchase, subject to certain exclusions, in a true sale, trade receivables generated by certain of our subsidiaries without recourse (other than customary indemnification obligations for breaches of specific representations and warranties) and then transfer undivided interests in up to $75.0 million of those accounts receivable to a financial institution for cash borrowings for our ultimate benefit. The total borrowings are limited by eligible accounts receivable, as defined under the terms of the A/R Securitization Program. At December 31, 2014, the A/R Securitization Program would have allowed for $52.1 million of borrowing capacity. There were no borrowings outstanding from the A/R Securitization Program at December 31, 2014 or December 31, 2013. The SPE is consolidated into our financial statements.

Credit Facility

On February 21, 2014, Cloud Peak Energy Resources LLC entered into a five-year Credit Agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders (the Credit Agreement). The Credit Agreement provides us with a senior secured revolving credit facility with a capacity of up to $500 million that can be used to borrow funds or issue letters of credit. The borrowing capacity under the Credit Agreement is reduced by the amount of letters of credit issued, which may be up to $250 million. Subject to the satisfaction of certain conditions, we may elect to increase the size of the revolving credit facility and/or request the addition of one or more new tranches of term loans in an amount up to the greater of (i) $200 million or (ii) our EBITDA (which is defined in the Credit Agreement) for the preceding four fiscal quarters. The Credit Agreement provides for the designation of a foreign restricted subsidiary as a borrower, subject to certain conditions and approvals.

On September 5, 2014, we entered into the First Amendment to the Credit Agreement (the Amendment). The Amendment adjusted the financial covenants under the Credit Agreement, which now require us to maintain (a) a ratio of EBITDA (as defined in the Credit Agreement) for the preceding four fiscal quarters to consolidated net cash interest expense equal to or greater than 1.50 to 1 from September 30, 2014 to maturity (reducing this from the prior requirement under the Credit Agreement to maintain a ratio equal to or greater than 2.00 to 1), and (b) a ratio of senior secured funded debt less unrestricted cash and marketable securities (net secured debt) to EBITDA for the preceding four fiscal quarters equal to or less than 4.00 to 1 from September 30, 2014 to maturity (increasing this from the prior requirement under the Credit Agreement to maintain a ratio equal to or less than (i) 3.00 to 1 through December 31, 2015, (ii) 2.75 to 1 from January 1, 2016 to December 31, 2016, and (iii) 2.50 to 1 from January 1, 2017 to maturity). This credit facility and capital leases are

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

considered senior secured funded debt under the covenant calculations whereas federal coal lease obligations, accounts receivable securitizations, and senior notes are not considered senior secured funded debt.

The Credit Agreement also contains other non-financial covenants, including covenants related to our ability to incur additional debt or take other corporate actions. The Credit Agreement also contains customary events of default with customary grace periods and thresholds. Our ability to access the available funds under the credit facility may be prohibited in the event that we do not comply with the covenant requirements or if we default on our obligations under the Credit Agreement. At December 31, 2014, we were in compliance with the covenants contained in our Credit Agreement.

Loans under the Credit Agreement bear interest at LIBOR plus an applicable margin of 2.00% to 2.75%, depending on our net total leverage to EBITDA ratio. We pay the lenders a commitment fee between 0.375% and 0.50% per year, depending on our net total leverage to EBITDA ratio, on the unused amount of the credit facility. Letters of credit issued under the credit facility, unless drawn upon, will incur a per annum fee from the date at which they are issued between 2.00% and 2.75% depending on our net total leverage to EBITDA ratio. Letters of credit that are drawn upon are converted to loans. In addition, in connection with the issuance of a letter of credit, we are required to pay the issuing bank a fronting fee of 0.125% per annum.

As of December 31, 2014, no borrowings or letters of credit were outstanding under the credit facility, and we were in compliance with the covenants contained in the Credit Agreement. Our aggregate borrowing capacity under the Credit Agreement and the A/R Securitization Program was approximately $552.1 million at December 31, 2014.

The Credit Agreement replaced our previous $500 million amended and restated credit agreement dated June 3, 2011. There were no borrowings outstanding under the previous credit facility at the time of replacement or at December 31, 2013. At the time of replacement, we recorded a charge of $2.2 million in interest expense to write off certain deferred financing costs as certain banks of the syndicate changed. We recorded $9.7 million of new deferred financing costs related to the new Credit Agreement and related Amendment. The aggregate deferred financing costs are being amortized on a straight-line basis to interest expense over the five-year term of the Credit Agreement.

Unamortized fees and costs were included in noncurrent other assets and totaled the following at December 31 (in thousands):

	2014	**2013**
Unamortized debt issuance costs	$ 10,587	$ 5,440

Our obligations under the Credit Agreement are secured by substantially all of our assets and substantially all of the assets of certain of our subsidiaries, subject to certain permitted liens and customary exceptions for similar coal financings. Our obligations under the Credit Agreement are also supported by a guarantee by CPE Inc. and our domestic restricted subsidiaries.

Under the Credit Agreement, the subsidiaries of CPE Inc. are permitted to make distributions to CPE Inc. to enable it to pay (i) federal, state and local income and certain other taxes it incurs that are attributable to the business and operations of its subsidiaries and (ii) amounts on the tax agreement liability, which was terminated in August 2014. In addition, as long as no default under the Credit Agreement exists, the subsidiaries of CPE Inc. also may make annual distributions to CPE Inc. to fund dividends or repurchases of CPE Inc. s stock and additional distributions in accordance with certain distribution limits in the Credit Agreement. Finally, the subsidiaries of CPE Inc. may make loans to CPE Inc. subject to certain limitations in the Credit Agreement.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Interest Expense

Interest expense consisted of the following (in thousands):

	Year Ended December 31, 2014	2013	2012
Senior notes	$ 40,702	$ 50,250	$ 50,250
Credit facility commitment fee	2,485	2,842	2,536
Federal coal lease obligations imputed interest	8,062	13,212	20,406
Amortization of deferred financing costs and original issue discount	4,321	4,499	3,960
Other	260	240	1,150
Subtotal	55,830	71,043	78,302
Premium on early retirement of debt	13,837		
Write-off of deferred financing costs and original issue discount	7,338		
Other	364		
Subtotal - cost of early retirement of debt and refinancings	21,538		
Total interest expense	77,368	71,043	78,302
Less interest capitalized	(208)	(29,378)	(41,975)
Net interest expense	$ 77,160	$ 41,665	$ 36,327

16. Asset Retirement Obligations

Changes in the carrying amount of our AROs were as follows (in thousands):

	2014	2013
Balance at January 1	$ 247,329	$ 240,634
Reduction in asset retirement obligation attributable to sale of Decker Mine interest (see Note 4)	(72,175)	
Accretion expense	15,136	15,342
Revisions to estimated cash flows	28,243	(7,572)
Payments	(1,221)	(1,075)
Balance at December 31	217,312	247,329
Less: current portion	(1,071)	(1,248)

Asset retirement obligation, net of current portion	$	216,241	$	246,081

The above amounts exclude $5.7 million and $7.4 million of concurrent reclamation for the years ended December 31, 2014 and 2013, respectively.

Revisions to estimated future reclamation cash flows reflect our regular updates to our estimated costs of closure activities throughout the lives of the respective mines and reflect changes in estimates of closure volumes, disturbed acreages, the timing of the reclamation activities, and third-party unit costs as of December 31, 2014.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Employee Benefit Plans

Our consolidated statements of operations include expenses in connection with employee benefit plans, as follows for the years ended December 31 (in thousands):

	2014	2013	2012
Cloud Peak Energy defined contribution retirement plans	$ 13,392	$ 13,495	$ 12,550
Cloud Peak Energy retiree medical plan	6,996	8,399	7,212
	20,388	21,894	19,762
Decker Mine pension plan (1)	884	1,248	889
Total	$ 21,272	$ 23,142	$ 20,651

(1) In connection with the sale of our 50% non-operating interest in the Decker Mine to Ambre Energy, the obligations under the Decker Mine pension plan were assumed by Ambre Energy.

Cloud Peak Energy Defined Contribution Retirement Plans

We sponsor two defined contribution plans to assist eligible employees in providing for retirement. Our employees may elect to contribute a portion of their salary on a pre- or post-tax basis to their accounts. We match all employee contributions up to 6% of eligible compensation. We also contribute an additional 6% of eligible compensation to employee accounts under one of the plans. All contributions are fully vested at the date of contribution. Total contributions for the years ended December 31 are as follows (in thousands):

	2014	2013	2012
Contributions	$ 13,392	$ 13,495	$ 12,550

Cloud Peak Energy Retiree Medical Plan

We provide certain postretirement medical coverage for eligible employees (the Retiree Medical Plan). Employees who are 55 years old and have completed ten years of service with us generally are entitled to receive benefits under the Retiree Medical Plan, except for employees who were eligible at the date of the IPO to receive benefits under the Rio Tinto retiree medical plan and elect to receive such benefits. Our retiree medical plan grants credit for service rendered by our employees to Rio Tinto prior to the IPO. This plan is unfunded.

Net periodic postretirement benefit costs included the following components (in thousands):

	2014	2013	2012
Service cost	$ 4,150	$ 4,951	$ 4,213
Interest cost	1,857	1,674	1,424
Amortization of prior service cost	989	1,775	1,575
Net periodic postretirement benefit cost	$ 6,996	$ 8,399	$ 7,212

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Annually, we remeasure and adjust the liability for the accumulated postretirement benefit obligation (APBO). Changes in the APBO include the following components (in thousands):

	2014	2013	2012
Beginning Balance	$ 39,172	$ 43,393	$ 33,166
Current period service costs	4,150	4,951	4,213
Interest costs	1,857	1,674	1,424
Plan amendment		(2,671)	
Benefits paid, net of retiree contributions	(46)	(21)	(74)
Change in actuarial assumptions	5,564	(8,154)	4,664
Ending Balance	50,697	39,172	43,393
Less current portion	421	311	231
Long-term APBO	$ 50,276	$ 38,862	$ 43,162

We used the following assumptions in the measurement of the APBO for the years ended December 31:

	2014	2013	2012
Discount rate	3.82%	4.76%	3.87%
Health care cost trend rate assumed for next year	6.50%	7.00%	7.50%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2018	2018	2018

During 2013, we modified the Retiree Medical Plan so that it is now considered a high-deductible health plan. This is considered a negative plan amendment, and we recorded a $2.7 million reduction to the liability which was offset to the unamortized portion of prior service costs included in Accumulated Other Comprehensive Income at December 31, 2014.

To determine the discount rate, we matched our cash projections against the Citigroup Pension Discount Curve. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point increase in the assumed health care cost trend would increase net periodic postretirement benefit cost and the APBO by $1.2 million and $6.0 million, respectively, and a one-percentage-point decrease in the rate would decrease net periodic postretirement benefit cost and the APBO by $1.0 million and $5.0 million, respectively, as of December 31, 2014.

Our estimated future benefit payments under the Retiree Medical Plan, which are net of estimated employee contributions and reflect expected future service, are as follows for the years ended December 31 (in thousands):

2015	$	421
2016		670
2017		996
2018		1,399
2019		1,889
2020-2024		16,104

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

18. Commitments and Contingencies

Commitments

Operating Leases

We occupy various facilities and lease certain equipment under various lease agreements. The minimum rental commitments under non-cancelable operating leases, with lease terms in excess of one year subsequent to December 31, 2014, are as follows (in thousands):

2015	$ 482
2016	458
2017	455
2018	454
2019	454
Thereafter	492

Rental expenses for the years ended December 31 were as follows (in thousands):

	2014	2013	2012
Rent expense	$ 2,326	$ 1,919	$ 3,103

Purchase Commitments

As of December 31, we had outstanding purchase commitments consisting of the following (in thousands):

	2014	2013
Capital commitments		
Equipment	$ 11,751	$ 5,851
Land	$ 24,663	$ 23,700

Supplies and services				
Coal purchase commitments	$	2,592	$	
Transportation agreements (1)	$	691,530	$	226,006
Materials and supplies	$	12,185	$	18,060

(1) As a result of amending our agreement with Westshore to increase our committed capacity, we substantially increased our rail and terminal take-or-pay commitments.

Contingencies

Litigation

WildEarth Guardians and Northern Plains Resource Council s Regulatory Challenge to OSM s Approval Process for Mine Plans

Background On February 27, 2013, WildEarth Guardians (WildEarth) filed a complaint in the United States District Court for the District of Colorado (Colorado District Court) challenging the federal Office of Surface Mining s (OSM) approvals of mine plans for seven different coal mines located in four different states. The challenged approvals included two that were issued to subsidiaries of Cloud Peak Energy: one for the Cordero Rojo Mine in Wyoming and one for the Spring Creek Mine in Montana.

On February 7, 2014, the Colorado District Court severed the claims in WildEarth s complaint and transferred all the claims pertaining to non-Colorado mines to the federal district courts for the states in which the mines were located. Pursuant to this order, the challenge to Cordero Rojo s mine plan approval (along with challenges to two other OSM

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

approvals) was transferred to the United States District Court in Wyoming (Wyoming District Court) and the challenge to Spring Creek s mine plan approval was transferred to the United States District Court for the District of Montana (Montana District Court). On February 14, 2014, WildEarth voluntarily dismissed the case pending in the Wyoming District Court, thereby concluding its challenge to OSM s approval of the Cordero mine plan. WildEarth has continued to pursue its challenges to mine plan approvals pending in district courts in Colorado, New Mexico, and Montana.

On March 14, 2014, WildEarth amended its complaint in the Montana District Court to reflect the transfer order from the Colorado District Court. WildEarth has asked the Montana District Court to vacate OSM s 2012 approval of the Spring Creek mine plan and enjoin mining operations at the Spring Creek Mine until OSM undertakes additional environmental analysis and related public process requested by WildEarth.

On August 14, 2014, Northern Plains Resource Council and the Western Organization of Resource Councils (collectively Northern Plains) filed a complaint in the Montana District Court challenging the same OSM approval of Spring Creek s mine plan. Northern Plains, like WildEarth, requested that the Montana District Court vacate OSM s 2012 approval of the Spring Creek mine plan and enjoin mining operations at the Spring Creek Mine until OSM undertakes the additional analysis requested by Northern Plains.

Intervention by Cloud Peak Energy and Others By orders dated May 30, 2014, May 9, 2014, and April 28, 2014, the Montana District Court granted intervention to the State of Montana, the National Mining Association, and Spring Creek Coal LLC, a 100% owned subsidiary of Cloud Peak Energy, respectively. Each of these parties intervened on the side of OSM.

Current Schedule On October 28, 2014, the Court consolidated the WildEarth and Northern Plains cases and set a briefing schedule for resolution of all of WildEarth s and Northern Plains claims through motions for summary judgment. Plaintiffs filed their opening briefs on December 8, 2014, and briefing by all parties is scheduled to be completed by April 28, 2015. Cloud Peak Energy believes WildEarth s challenge and the related Northern Plains challenge against OSM are without merit.

Montana Environmental Information Center and Sierra Club Regulatory Challenge to Montana DEQ s Coal Permit Program

Background On April 17, 2012, the Montana Environmental Information Center and the Sierra Club (collectively, MEIC) filed a complaint in the Montana District Court against the Director of the Montana Department of Environmental Quality (DEQ Director) alleging that the DEQ Director violated his nondiscretionary duties under the Surface Mining Control and Reclamation Act (SMCRA) by approving state mine permits without establishing numeric water quality standards as part of MT DEQ s cumulative hydrologic impact assessments (CHIAs) for coal mines. MEIC asked the Montana District Court to issue an order directing the DEQ Director to perform CHIAs in a manner requested by plaintiff organizations, and to enjoin the DEQ Director s approval of new mine permit applications until this analysis is completed.

Intervention by Cloud Peak Energy and Others On August 3, 2012, the Montana District Court granted the intervention motion of a number of other companies that own coal mines and/or coal reserves, the Crow Tribe, a labor union representing mine workers, and Spring Creek Coal LLC, a 100% owned subsidiary of Cloud Peak Energy. All these parties jointly intervened on the side of the DEQ Director.

District Court Rejection of Challenge and MEIC Appeal On January 22, 2013, the Montana District Court dismissed MEIC s challenge on the ground that the action was barred by Montana s 11th Amendment Sovereign Immunity. The Montana District Court also held that the DEQ Director s CHIAs were discretionary actions and therefore not subject to SMCRA s citizen suit provision, and alternatively, that MEIC s claims were not ripe for judicial review. On February 20, 2013, MEIC appealed to the United States Court of Appeals for the Ninth Circuit and asked the Ninth Circuit to reverse the judgment of the Montana District Court dismissing MEIC s case. Spring Creek and the other intervenors in the Montana District Court intervened in this appeal as respondents on the side of the DEQ Director.

Court of Appeals Rejection of Challenge On September 11, 2014, the Ninth Circuit Court of Appeals issued a unanimous decision affirming the Montana District Court s dismissal of MEIC s complaint. MEIC declined to seek further review in the Ninth Circuit and the Court s mandate was issued on October 6, 2014. MEIC did not petition the Supreme Court for review of the Ninth Circuit s decision and the appeal is now concluded.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Administrative Appeals of BLM s Approval of the Potential West Antelope II South Lease Modification

Background On September 5, 2014, WildEarth filed an appeal with the Interior Board of Land Appeals (IBLA) challenging the Bureau of Land Management s (BLM) August 15, 2014 decision to approve Antelope Coal LLC s proposed modification of Antelope Coal s West Antelope II South Lease. Antelope Coal is a 100% owned subsidiary of Cloud Peak Energy. On September 12, 2014, Powder River Basin Resource Council and Sierra Club (collectively PRBRC) filed an appeal with the IBLA challenging this same BLM decision. The BLM decision that is the subject of both appeals approves the proposed amendment of Antelope Coal s West Antelope II South Lease. If the lease modification is entered into, it would add approximately 15.8 million tons of coal underlying nearly 857 surface acres. WildEarth and PRBRC have asked the IBLA to vacate the proposed WAII South lease modification and direct BLM to prepare additional environmental analysis on the impacts of the lease modification.

Intervention by Cloud Peak Energy and State of Wyoming On September 24, 2014 and October 6, 2014, Antelope Coal and the State of Wyoming, respectively, moved to intervene in the WildEarth and PRBRC appeals as respondents to defend BLM s lease modification decision. The IBLA granted these intervention motions.

Current Schedule. WildEarth filed its Statement of Reasons (opening brief) on October 6, 2014, and PRBRC filed its Statement of Reasons on October 10, 2014. BLM filed its Answer (opposition brief) on January 12, 2015 and moved for the two appeals to be consolidated. Antelope Coal and State of Wyoming filed their respective Answers on January 20, 2015. Briefing is expected to be completed in both appeals in February 2015. Cloud Peak Energy believes the WildEarth and PRBRC appeals challenging BLM s West Antelope II South lease modification decision are without merit.

Other Legal Proceedings

We are involved in other legal proceedings arising in the ordinary course of business and may become involved in additional proceedings from time to time. We believe that there are no other legal proceedings pending that are likely to have a material adverse effect on our consolidated financial condition, results of operations or cash flows. Nevertheless, we cannot predict the impact of future developments affecting our claims and lawsuits, and any resolution of a claim or lawsuit or an accrual within a particular fiscal period may adversely impact our results of operations for that period. In addition to claims and lawsuits against us, our LBAs, LBMs, permits, and other industry regulatory processes and approvals, including those applicable to the utility and coal logistics and transportation industries, may also be subject to legal challenges that could adversely impact our mining operations and results.

Tax Contingencies

Our income tax calculations are based on application of the respective U.S. federal or state tax laws. Our tax filings, however, are subject to audit by the respective tax authorities. Accordingly, we recognize tax benefits when it is more likely than not a position will be upheld by the tax authorities. To the extent the final tax liabilities are different from the amounts originally accrued, the increases or decreases are recorded as income tax expense.

Several non-income based production tax audits currently are in progress related to federal and state royalties and severance taxes, including periods back to 2005. We have provided our best estimate of taxes and related interest and penalties due for potential adjustments that may result from the resolution of such tax audits. From time to time, we receive audit assessments and engage in settlement discussions with applicable tax authorities, which may result in adjustments to our estimates of taxes and related interest and penalties. During 2014, we revised our estimates and increased our accruals by $9.6 million.

Concentrations of Risk and Major Customers

Approximately 79%, 83%, and 93% of our revenue for the years ended December 31, 2014, 2013, and 2012, respectively, were under multi-year contracts. While the majority of the contracts are fixed-price contracts, certain contracts have adjustment provisions for determining periodic price changes. There was no single customer that represented 10% or more of consolidated revenue in 2014, 2013, or 2012. We generally do not require collateral or other security on accounts receivable because our customers are comprised primarily of investment grade electric utilities. The credit risk is controlled through credit approvals and monitoring procedures.

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Guarantees and Off-Balance Sheet Risk

In the normal course of business, we are party to guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit, performance or surety bonds and indemnities, which are not reflected on the consolidated balance sheet. In our past experience, virtually no claims have been made against these financial instruments. Management does not expect any material losses to result from these guarantees or off-balance-sheet instruments.

U.S. federal and state laws require we secure certain of our obligations to reclaim lands used for mining and to secure coal lease obligations. The primary method we have used to meet these reclamation obligations and to secure coal lease obligations is to provide a third-party surety bond, typically through an insurance company, or provide a letter of credit, typically through a bank. Specific bond and/or letter of credit amounts may change over time, depending on the activity at the respective site and any specific requirements by federal or state laws. On May 7, 2014, we were granted approval from the state of Wyoming to self-bond $200 million of our reclamation obligations within the state. As of December 31, 2014, we were self-bonded for $200 million and had $448.9 million of surety bonds outstanding to secure certain of our obligations to reclaim lands used for mining and to secure coal lease obligations.

On September 12, 2014, we completed the sale of our 50% non-operating interest in the Decker Mine to Ambre Energy. See Note 4. Upon completion, Ambre Energy fully replaced our $66.7 million in outstanding reclamation and lease bonds related to the Decker Mine.

19. Income Taxes

Our income before income tax provision and earnings from unconsolidated affiliates is earned solely in the U.S.

The income tax expense (benefit) consisted of the following for the years ended December 31 (in thousands):

	2014	2013	2012
Current:			
Federal	$ 2,383	$ (2,325)	$ 18,064
State	609	95	2,339
Total current	2,992	(2,230)	20,403
Deferred:			
Federal	30,873	15,500	40,351
State	1,048	(1,640)	1,859

Total deferred		31,921		13,860		42,210
Total income tax expense	$	34,913	$	11,629	$	62,614

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The tax effects of temporary differences that result in deferred tax assets and deferred tax liabilities consisted of the following at December 31 (in thousands):

	2014	2013
Deferred income tax assets:		
Property, plant and equipment	$	$ 6,870
Accrued expense and liabilities	35,413	34,221
Pension and other postretirement benefits	18,656	14,642
Investment in joint venture partnerships		2,514
Accrued reclamation and mine closure costs	55,628	49,143
Contract rights	26,989	33,460
Tax agreement liability		38,047
AMT Credit	32,025	29,591
Net operating loss carry forward	3,523	10,627
Other		1,401
Total deferred income tax assets	172,234	220,516
Less valuation allowance	(7,150)	(12,711)
Net deferred income tax asset	165,084	207,805
Deferred income tax liabilities:		
Property, plant and equipment	(1,245)	
Inventories	(1,484)	(2,633)
Mineral rights	(75,732)	(79,571)
Mark-to-market gain	(3,486)	(9,639)
Other	(4,999)	(6,275)
Total deferred income tax liabilities	(86,946)	(98,118)
Net deferred income tax assets (liabilities)	$ 78,138	$ 109,687

We report the tax effects of differences between tax bases of assets and liabilities and the financial statement carrying amount of these items as deferred income tax assets and liabilities. Also included in other deferred tax assets are net operating loss carryforwards of $8.6 million that expire in 2029 through 2033 and alternative minimum tax (AMT) credits of $32.0 million that do not expire.

Net deferred income tax assets are classified in the consolidated balance sheets at December 31 as follows (in thousands):

	2014	2013
Net current deferred income tax assets	$ 21,670	$ 18,326
Net noncurrent deferred income tax assets	56,468	91,361
Net deferred income tax assets	$ 78,138	$ 109,687

The future realization of deferred income tax assets arising primarily from the increased tax basis arising from the IPO and the Secondary Offering depends on the existence of sufficient future taxable income. Based on our consideration of CPE Resources s historical operations, current forecasts of taxable income over the remaining lives of our mines, the availability of tax planning strategies, and other factors, we determined that $165.1 million of the potential tax benefits are more likely than not to be realized at the statutory federal and state income tax rates. Accordingly, we have provided a $7.2 million valuation allowance to reduce our deferred tax assets to the amount that we determined is more likely than not to be realized.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The effective tax rate is reconciled to the U.S. federal statutory income tax rate for the years ended December 31 as follows:

	2014	2013	2012
United States federal statutory income tax rate	35.0%	35.0%	35.0%
State income taxes, net of federal tax benefit	1.3	(2.4)	1.2
Percentage depletion deduction	(0.7)	(7.3)	(2.3)
Section 199 domestic manufacturing deduction	(0.5)		(0.6)
Change in valuation allowance	(4.9)	(7.1)	(7.1)
Prior year return-to-actual	0.1	(0.4)	0.3
Other	0.5	0.6	0.2
Effective tax rate	30.8%	18.4%	26.7%

The estimated statutory income tax rates that are applied to our current and deferred income tax calculations are impacted significantly by the states in which we do business. Changes in apportionment laws or business conditions result in changes in the calculation of our current and deferred income taxes, including the valuation of our deferred tax assets and liabilities. Such adjustments can increase or decrease the net deferred tax asset on the balance sheet and impact the corresponding deferred tax benefit or deferred tax expense on the income statement in the period.

As of December 31, 2014, 2013, and 2012, we had no uncertain tax positions that we expect to have a material impact on the financial statements as a result of tax deductions taken during the year or in prior periods or due to settlements with taxing authorities or lapses of applicable statute of limitations. We are open to federal and state tax audits until the applicable statutes of limitations expire.

20. Equity-Based Compensation

The Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (LTIP) permits awards to our employees and eligible non-employee directors, which we generally grant in the first quarter of each year. The LTIP allows for the issuance of equity-based compensation in the form of restricted stock, restricted stock units, options, stock appreciation rights, dividend equivalent rights, performance awards, and share awards. In May 2011, the stockholders approved increasing the pool of shares of CPE Inc. s common stock authorized for issuance in connection with equity-based awards under the LTIP from 3.4 million shares to 5.5 million shares. As of December 31, 2014, 2.5 million shares were available for grant.

Generally, each form of equity-based compensation awarded to eligible employees cliff vests on the third anniversary of the grant date, subject to meeting any applicable performance criteria for the award. However, the awards will pro-rata vest sooner if an employee terminates employment with or stops providing services to us because of death, disability, redundancy or retirement (as such terms are defined in the award agreement or the LTIP, as applicable), or if an employee subject to an employment agreement is terminated for any other reason than for cause or leaves for good reason (as such terms are defined in the relevant employment agreement). In addition, the awards will fully vest if an employee is terminated without cause (or leaves for good reason, if the employee is subject to an employment agreement) within two years after a change in control (as such term is defined in the LTIP) occurs.

Total equity-based compensation expense recognized primarily within selling, general, and administrative expenses in our consolidated statements of operations was as follows for the years ended December 31 (in thousands):

	2014	2013	2012
Total equity-based compensation expense	$ 7,966	$ 8,016	$ 11,796

Restricted Stock and Restricted Stock Units

We granted restricted stock and restricted stock units under the LTIP to eligible employees, and we granted restricted stock units to our non-employee directors. The restricted stock units granted to our directors generally vest upon their resignation or retirement (except for a removal for cause) or upon certain events constituting a change in control (as such term is defined in the award agreement). They will pro-rata vest if a director resigns or retires within one year of the date of grant.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A summary of restricted stock award activity is as follows (in thousands):

	Number		Weighted Average Grant-Date Fair Value (per share)
Non-vested shares at January 1, 2014	372	$	18.51
Granted	137		18.75
Vested	(92)		20.49
Forfeited	(10)		18.65
Non-vested shares at December 31, 2014	407	$	18.14

As of December 31, 2014, unrecognized compensation cost related to restricted stock awards was $2.2 million, which will be recognized over a weighted-average period of 1.7 years prior to vesting. The total fair value of restricted stock awards vested during the years ended December 31, 2014, 2013, and 2012 was $1.6 million, $1.1 million, and $15.1 million, respectively.

Performance-Based Share Units

Performance-based share units granted represent the number of shares of common stock to be awarded based on the achievement of targeted performance levels related to pre-established total stockholder return goals over a three-year period and may range from 0% to 200% of the targeted amount. The grant date fair value of the awards is based upon a Monte Carlo simulation and is amortized over the performance period.

A summary of performance-based share unit award activity is as follows (in thousands):

	Number		Weighted Average Grant-Date Fair Value (per share)
Non-vested units at January 1, 2014	415	$	18.94
Granted	202		25.63
Forfeited	(14)		22.49
Expired (1)	(106)		17.61
Non-vested units at December 31, 2014	497	$	21.84

(1) Represents units that did not achieve the targeted performance goal.

The assumptions used to estimate the fair value of the performance-based share units granted during the year ended December 31, are as follows:

	2014	2013	2012
Risk-free interest rate	0.7%	0.4%	0.5%
Expected volatility	38.3%	42.5%	48.2%
Term	2.8	3 years	3 years
Fair Value (per share)	$ 25.63	$ 20.24	$ 17.61

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2014, unrecognized compensation cost related to performance-based share units was $4.4 million which will be recognized over a weighted-average period of 1.8 years prior to vesting. No shares have vested yet under outstanding performance-based share awards.

Non-Qualified Stock Options

Annually, we have granted non-qualified stock options under the LTIP to certain employees. All unexercised options will expire ten years after the date of grant unless expiring earlier following a termination of employment as described below. Generally, vested options will expire 30 days after the date of the grantee s termination of employment with us (one year in the event of a termination due to the grantee s death, and 90 days following a qualifying termination within the two-year period following a change in control).

A summary of non-qualified stock option activity is as follows (in thousands except per share amounts):

	Number	Weighted Average Exercise Price (per option)	Weighted Average Contractual Term (years)	Aggregate Intrinsic Value(1)
Options outstanding at January 1, 2014	1,439	$ 16.17	6.70	$ 2,999
Granted	219	19.35		
Exercised	(215)	15.00		935
Forfeited	(14)	18.36		26
Expired	(5)	18.70		
Options outstanding at December 31, 2014	1,424	$ 16.80	6.40	$
Exercisable at December 31, 2014	828	$ 15.93	5.10	$
Vested and expected to vest at December 31, 2014	1,378	$ 16.72	6.30	$

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at year-end.

As of December 31, 2014, we had $1.9 million of unrecognized compensation expense, net of estimated forfeitures, for non-vested stock options, which will be recognized as expense over the remaining weighted-average vesting period of approximately 1.7 years. The intrinsic value of options exercised during the years ended December 31, 2014 and 2013 was $0.9 million and $0.3 million, respectively.

We used the Black-Scholes option pricing model to determine the fair value of stock options. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock options will be outstanding prior to exercise, and the associated volatility. As we have limited historical exercise history, expected option life assumptions were developed using the simplified method as outlined in Topic 14, *Share-Based Payment*, of the Staff Accounting Bulletin Series. We utilized U.S. Treasury yields as of the grant date for our risk-free interest rate assumption, matching the treasury yield terms to the expected life of the option. We blended our limited historical volatility with a 6.5 year peer historical lookback to develop our expected volatility.

The assumptions used to estimate the fair value of options granted during the years ended December 31, are as follows:

	2014	2013	2012
Weighted-average grant date fair value (per option)	$ 8.89	$ 8.72	$ 9.05
Assumptions:			
Risk-free interest rate	2.1%	1.4%	1.7%
Expected option life	6.5 years	6.5 years	6.5 years
Expected volatility	43.3%	49.7%	53.6%

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Employee Stock Purchase Plan

In May 2011, our stockholders approved the Cloud Peak Energy Inc. Employee Stock Purchase Plan (ESPP). Eligible employees are able to authorize payroll deductions on a voluntary basis to purchase shares of CPE Inc. s common stock at a discount from the market price. A maximum of 500,000 shares of common stock have been reserved for sale under the ESPP. Employees are eligible to participate in the ESPP if employed by us for at least six months and are expected to work at least 1,000 hours of service per calendar year. Participating employees may contribute up to $200 of their eligible earnings during each pay period or $4,800 per plan year. The purchase price of common stock purchased under the ESPP is equal to the lesser of (i) 90% of the fair market value of CPE Inc. s common stock on the offering date and (ii) 90% of the fair market value of CPE Inc. s common stock on the last day of the annual option period.

Compensation costs related to the ESPP are as follows (in thousands):

	2014	2013	2012
Unrecognized compensation expense	$ 172	$ 190	$ 263
Recognized compensation expense	276	377	131
Total ESPP compensation expense	$ 448	$ 567	$ 394

The fair value of each purchase right granted under the ESPP was estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions:

	2014	2013	2012
Weighted-average fair value (per award)	$ 3.96	$ 4.28	$ 5.51
Assumptions:			
Risk-free interest rate	0.1%	0.1%	0.2%
Expected option life	1.0	1.0	1.0
Expected volatility	28.0%	33.1%	44.7%

21. Accumulated Other Comprehensive Income (Loss)

The changes in Accumulated Other Comprehensive Income (Loss) (AOCI) by component, net of tax are as follows (in thousands):

	Post-retirement	Decker Defined	Total

	Medical Plan	Benefit Pension	
Beginning balance, January 1, 2012	$ (14,432)	$ (4,182)	$ (18,614)
Other comprehensive income before reclassifications	(2,986)	130	(2,856)
Amounts reclassified from accumulated other comprehensive income	1,009		1,009
Net current period other comprehensive loss	(1,977)	130	(1,847)
Ending balance, December 31, 2012	(16,409)	(4,052)	(20,461)
Other comprehensive income before reclassifications	7,017	2,014	9,031
Amounts reclassified from accumulated other comprehensive income	1,151		1,151
Net current period other comprehensive income (loss)	8,168	2,014	10,182
Ending balance, December 31, 2013	(8,242)	(2,038)	(10,279)
Other comprehensive income before reclassifications	(3,691)		(3,691)
Amounts reclassified from accumulated other comprehensive income	633	2,038	2,671
Net current period other comprehensive income	(3,058)	2,038	(1,020)
Ending balance, December 31, 2014	$ (11,299)	$	$ (11,299)

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The reclassifications out of AOCI are as follows (in thousands):

	Year Ended December 31, 2014	2013	2012
Postretirement Medical Plan(1)			
Amortization of prior service costs included in cost of product sold(2)	$ 836	$ 1,482	$ 1,326
Amortization of prior service costs included in selling, general and administrative expenses(2)	153	293	249
Write-off of Decker Mine pension prior service costs included in gain on sale of Decker Mine interest	3,183		
Total before tax	4,172	1,775	1,575
Tax benefit	(1,501)	(624)	(566)
Amounts reclassified from accumulated other comprehensive income	$ 2,671	$ 1,151	$ 1,009

(1) See Note 17 for the computation of net periodic postretirement benefit costs.

(2) Presented on the consolidated statements of operations and comprehensive income.

22. Capital Stock and Earnings Per Share

Common Stock

We have 200.0 million authorized shares of $0.01 par value common stock. The holders of our common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the shareholders. Our shareholders do not have cumulative voting rights in the election of directors. Subject to preferences that may be granted to any then-outstanding preferred stock, holders of our common stock are entitled to receive ratably only those dividends that the board of directors may from time to time declare, and we may pay, on our outstanding shares in the manner and upon the terms and conditions provided by law. See Item 5 Market for Registrant s Common Equity and Related Stockholder Matters Dividend Policy. In general, in the event of our liquidation, dissolution or winding up, holders of our common stock are entitled to share ratably in our assets, if any, remaining after we pay our liabilities and distribute the liquidation preference of any then-outstanding preferred stock. Holders of our common stock have no pre-emptive or other subscription or conversion rights. There are no redemption or sinking fund provisions applicable to our common stock.

Preferred Stock

Per our Amended and Restated Certificate of Incorporation, which was effective as of November 25, 2009, our board of directors is authorized to issue up to 20 million shares of preferred stock, $0.01 par value. The board of directors can determine the terms and rights, preferences, privileges and restrictions of each series. These rights, preferences, and privileges may include dividend rights, conversion rights, voting rights, terms of redemption, liquidation preferences, sinking fund terms, and the number of shares constituting any series or the designation of this series. There were no outstanding shares of preferred stock as of December 31, 2014.

Treasury Stock

We allow employees to relinquish common stock to pay estimated taxes upon the vesting of restricted stock and upon the payout of performance units that settled in common stock. The value of the common stock withheld is based upon the closing price on the vesting date.

Earnings per Share

Dilutive potential shares of common stock include restricted stock and options issued under the LTIP (see Note 20). We apply the treasury stock method to determine dilution from restricted stock and options. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

included in the diluted share computation. For our performance units, the contingent feature results in an assessment for any potentially dilutive common stock by using the end of the reporting period as it were the end of the contingency period.

The following table summarizes the calculation of basic and diluted earnings per share for the years ended December 31, (in thousands, except per share amounts):

	2014	2013	2012
Numerator for calculation of basic earnings per share:			
Net income	$ 78,960	$ 51,971	$ 173,720
Denominator for basic income per share:			
Weighted-average shares outstanding	60,826	60,652	60,093
Basic earnings per share	$ 1.30	$ 0.86	$ 2.89
Numerator for calculation of diluted earnings per share:			
Net income	$ 78,960	$ 51,971	$ 173,720
Denominator for diluted income per share:			
Weighted-average shares outstanding	60,826	60,652	60,093
Dilutive effect of stock equivalents	469	509	834
Denominator for diluted earnings per share	61,295	61,161	60,927
Diluted earnings per share	$ 1.29	$ 0.85	$ 2.85

For the years ended December 31, the following were excluded from the diluted earnings per share calculation because they were anti-dilutive (in thousands):

	2014	2013	2012
Restricted stock	252	196	28
Options outstanding	732	495	57
Employee stock purchase plan	1	21	21

23. Related Party Transactions

Related party activity consists primarily of coal sales to our equity method investment, Venture Fuels Partnership, for delivery of coal under arms-length commercial arrangements in the ordinary course of business.

The following table summarizes related party transactions for the years ended December 31 (in thousands):

	2014	2013	2012
Sales of coal to Venture Fuels Partnership	$ 20,755	$ 19,708	$ 22,069

24. Segment Information

We have reportable segments of Owned and Operated Mines, Logistics and Related Activities, and Corporate and Other.

Our Owned and Operated Mines segment is characterized by the predominant focus on thermal coal production where the sale occurs at the mine site and where title and risk of loss pass to the customer at that point. This segment includes our Antelope Mine, Cordero Rojo Mine, and Spring Creek Mine. Sales in this segment are primarily to domestic electric utilities, although a portion is made to our Logistics and Related Activities segment. Sales between reportable segments are based on prevailing market prices. Our mines utilize surface mining extraction processes and are all located in the PRB. The gains and losses resulting from our domestic coal futures contracts and WTI derivative financial instruments are reported within this segment.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our Logistics and Related Activities segment is characterized by the services we provide to our international and domestic customers where we deliver coal to the customer at a terminal or the customer s plant or other delivery point, remote from our mine site.Services provided include the purchase of coal from third parties or from our owned and operated mines, at market prices, as well as the contracting and coordination of the transportation and other handling services from third-party operators, which are typically rail and terminal companies. Title and risk of loss are retained by the Logistics and Related Activities segment through the transportation and delivery process. Title and risk of loss pass to the customer in accordance with the contract and typically occur at a vessel loading terminal, a vessel unloading terminal or an end use facility. Risk associated with rail and terminal take-or-pay agreements is also borne by the Logistics and Related Activities segment. The gains and losses resulting from our international coal forward derivative financial instruments are reported within this segment. Port access contract rights and related amortization are also included in this segment.

Our Corporate and Other segment includes results relating to broker activity, our previous share of the Decker Mine operations, which was sold on September 12, 2014, and unallocated corporate costs and assets. All corporate costs, except Board of Directors related expenses, are allocated to the segments based upon their relative percentage of certain financial metrics.

Eliminations represent the purchase and sale of coal between reportable segments and the associated elimination of intercompany profit or loss in inventory.

Our chief operating decision maker uses Adjusted EBITDA as the primary measure of segment reporting performance. EBITDA represents income (loss) from continuing operations, or net income (loss), as applicable, before: (1) interest income (expense) net, (2) income tax provision, (3) depreciation and depletion, and (4) amortization. Adjusted EBITDA represents EBITDA as further adjusted for accretion, which represents non-cash increases in asset retirement obligation liabilities resulting from the passage of time, and specifically identified items that management believes do not directly reflect our core operations. For the periods presented herein, the specifically identified items are: (1) adjustments to exclude the updates to the tax agreement liability, including tax impacts of the IPO and Secondary Offering and the termination of the TRA in August 2014, (2) adjustments for derivative financial instruments, excluding fair value mark-to-market gains or losses and including cash amounts received or paid, (3) adjustments to exclude the gain from the sale of our 50% non-operating interest in the Decker Mine, and (4) adjustments to exclude a significant broker contract that expired in the first quarter of 2010.

Revenue

The following table presents revenue for the years ended December 31, (in thousands):

	2014	2013	2012
Owned and Operated Mines	$ 1,132,012	$ 1,137,542	$ 1,205,652
Logistics and Related Activities	224,938	265,865	338,804
Corporate and Other	22,809	49,367	37,984

Eliminations of intersegment sales	(55,716)	(56,677)	(65,668)
Consolidated revenue	$ 1,324,044	$ 1,396,097	$ 1,516,772

The following table presents revenue from external customers by geographic region for the years ended December 31, (in thousands):

	2014	2013	2012
United States	$ 1,126,264	$ 1,148,235	$ 1,211,755
South Korea	152,988	165,172	265,166
Other	44,792	82,690	39,851
Total revenue from external customers	$ 1,324,044	$ 1,396,097	$ 1,516,772

We attribute revenue to individual countries based on the location of the physical delivery of the coal. All of our revenue for the years ended December 31, 2014, 2013, and 2012 originated in the U.S.

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Adjusted EBITDA

The following table reconciles segment Adjusted EBITDA to net income (loss) for the years ended December 31, (in thousands):

	2014	2013	2012
Owned and Operated Mines	$ 196,973	$ 201,987	$ 283,280
Logistics and Related Activities	4,069	11,395	57,080
Corporate and Other	2,128	5,980	36
Eliminations	(1,227)	(792)	(1,568)
Consolidated Adjusted EBITDA	201,942	218,571	338,828
Interest expense, net	(76,901)	(41,225)	(35,241)
Depreciation, depletion and accretion	(127,158)	(115,865)	(107,764)
Income tax	(34,913)	(11,629)	(62,614)
Tax agreement benefit (expense)(1)	58,595	(10,515)	29,000
Derivative financial instruments:			
Exclusion of fair value mark-to-market gains (losses)(2)	7,805	25,611	22,754
Inclusion of cash amounts (received) paid(3)(4)	(24,672)	(12,976)	(11,244)
Total derivative financial instruments	(16,867)	12,635	11,511
Gain on sale of Decker Mine interest	74,262		
Net income	$ 78,960	$ 51,971	$ 173,720

(1) Changes to related deferred taxes are included in income tax expense.

(2) Fair value mark-to-market (gains) losses reflected on the statement of operations.

(3) Cash gains and losses reflected within operating cash flows.

(4) Excludes premiums paid at contract inception during the period.	$ 4.0	$	$

Total Assets

The following table presents total assets at December 31, (in thousands):

	2014	2013
Owned and Operated Mines	$ 1,704,267	$ 1,761,406

Logistics and Related Activities	92,347	55,770
Corporate and Other	363,611	540,432
Eliminations	(307)	(183)
Consolidated assets	$ 2,159,918	$ 2,357,425

As of December 31, 2014, 2013, and 2012, all of our long-lived assets were located in the U.S.

Capital Expenditures

The following table presents purchases of property, plant and equipment, investment in development projects, port access contract rights, and assets acquired under capital leases for the years ended December 31, (in thousands):

	2014	2013	2012
Owned and Operated Mines	$ 19,273	$ 55,663	$ 345,562
Logistics and Related Activities	39,260	2,497	7,389
Corporate and Other	4,177	5,089	8,365
Eliminations			
Consolidated	$ 62,710	$ 63,249	$ 361,316

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

25. Summary Unaudited Quarterly Financial Information

A summary of the unaudited quarterly results of operations for the years ended December 31, 2014 and 2013 is presented below (in thousands except per share amounts).

	Year Ended December 31, 2014			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 319,066	$ 320,850	$ 342,337	$ 341,791
Operating income	16,124	7,428	85,844	22,407
Net income (loss)	(15,626)	(2,148)	91,069	5,665
Income per common share from continuing operations attributable to the controlling interest:				
Basic	$ (0.26)	$ (0.04)	$ 1.50	$ 0.09
Diluted	$ (0.26)	$ (0.04)	$ 1.49	$ 0.09

	Year Ended December 31, 2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$ 338,052	$ 329,996	$ 374,816	$ 353,234
Operating income	34,619	17,067	33,831	26,865
Net income (loss)	15,395	4,709	17,966	13,901
Income (loss) per common share from continuing operations attributable to the controlling interest:				
Basic	$ 0.25	$ 0.08	$ 0.30	$ 0.23
Diluted	$ 0.25	$ 0.08	$ 0.29	$ 0.23

During the three months ended September 30, 2014, we completed the sale of our 50% non-operating interest in the Decker Mine, which resulted in a non-cash gain of $74.3 million. In addition, we entered into an acceleration and release agreement with Rio Tinto whereby we agreed to pay $45.0 million to Rio Tinto to terminate the TRA. The termination of the TRA resulted in a non-cash gain of $37.1 million after adjustments to the associated deferred tax assets. Fourth quarter 2014 net income included an out of period adjustment that decreased tax expense by $0.6 million.

During the three months ended September 30, 2013, we completed our update of our operating plans, inclusive of market and cash cost forecasts, and calculation of the resulting amount and timing of estimated future taxable income. Because of the reduced future tax value expected to be received, there was a decrease in the tax agreement liability due to Rio Tinto, resulting in a benefit to non-operating income for the three months ended September 30, 2013. In addition, the deferred tax valuation allowance was reduced based the update of the operating plans, resulting in a benefit to income tax expense.

26. Supplemental Guarantor/Non-Guarantor Financial Information

On March 25, 2014, Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp. (together with Cloud Peak Energy Resources LLC, the Issuers), Cloud Peak Energy Inc., Wilmington Trust Company, as trustee, and Citibank N.A. as securities administrator, entered into the fifth supplemental indenture (the Fifth Supplemental Indenture) to the indenture governing the Issuers 8.250% Senior Notes due 2017 (which are no longer outstanding) and 8.500% Senior Notes due 2019 (collectively, the Notes). Pursuant to the Fifth Supplemental Indenture, CPE Inc. has agreed to guarantee the Notes and to be bound by the terms of the indenture governing the Notes applicable to guarantors. As a result of such guarantee, and pursuant to Rule 12h-5 promulgated under the Securities Exchange Act of 1934 (Exchange Act) and Rule 3-10 of Regulation S-X, Cloud Peak Energy Resources LLC is no longer required to file reports under Section 15(d) of the Exchange Act and has filed a Form 15 in connection therewith.

In accordance with the indentures governing the senior notes, CPE Inc. and certain of our 100% owned U.S. subsidiaries (the Guarantor Subsidiaries) have fully and unconditionally guaranteed the senior notes on a joint and several basis. These guarantees of either series of senior notes are subject to release in the following customary circumstances:

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- a sale or other disposition (including by way of consolidation or merger or otherwise) of the Guarantor Subsidiary or the sale or disposition of all or substantially all the assets of the Guarantor Subsidiary (other than to CPE Inc. or a Restricted Subsidiary (as defined in the applicable indenture) of CPE Inc.) otherwise permitted by the applicable indenture,

- a disposition of the majority of the capital stock of a Guarantor Subsidiary to a third person otherwise permitted by the applicable indenture, after which the applicable Guarantor Subsidiary is no longer a Restricted Subsidiary,

- upon a liquidation or dissolution of a Guarantor Subsidiary so long as no default under the applicable indenture occurs as a result thereof,

- the designation in accordance with the applicable indenture of the Guarantor Subsidiary as an Unrestricted Subsidiary or the Guarantor Subsidiary otherwise ceases to be a Restricted Subsidiary of CPE Inc. in accordance with the applicable indenture,

- defeasance or discharge of such series of senior notes; or

- the release, other than the discharge through payment by the Guarantor Subsidiary, of all other guarantees by such Restricted Subsidiary of Debt (as defined in the applicable indenture) of either issuer of the senior notes or (in the case of the indenture for the 2024 Notes) the debt of another Guarantor Subsidiary under the Credit Agreement.

The following historical financial statement information is provided for CPE Inc. and the Guarantor/Non-Guarantor Subsidiaries:

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Operations and Comprehensive Income

(in thousands)

	Year Ended December 31, 2014					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ 8,796	$	$ 1,308,391	$ 15,653	$ (8,796)	$ 1,324,044
Costs and expenses						
Cost of product sold (exclusive of depreciation, depletion, amortization and accretion, shown separately)		215	1,076,154	17,841		1,094,211
Depreciation and depletion		2,994	110,196	(1,168)		112,022
Accretion			12,333	2,803		15,136
Derivative financial instruments			(7,805)			(7,805)
Selling, general and administrative expenses	8,795	650	49,552		(8,796)	50,201
Other operating costs		46	2,693			2,739
Total costs and expenses	8,795	3,905	1,243,123	19,476	(8,796)	1,266,504
Gain on sale of Decker Mine interest			(74,262)			(74,262)
Operating income (loss)	1	(3,905)	139,530	(3,823)		131,802
Other income (expense)						
Interest income		259				259
Interest expense		(68,064)	(8,710)	(386)		(77,160)
Tax agreement benefit (expense)	58,595					58,595
Other, net		(999)	374	422		(202)
Total other (expense) income	58,595	(68,804)	(8,336)	36		(18,508)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	58,596	(72,709)	131,194	(3,787)		113,294
Income tax benefit (expense)	(20,439)	11,909	(27,889)	1,505		(34,913)
Earnings from unconsolidated affiliates, net of tax		(4)	584			579
Earnings (losses) from consolidated affiliates, net of tax	40,803	101,607	(2,282)		(140,128)	
Net income (loss)	78,960	40,803	101,607	(2,282)	(140,128)	78,960
Other comprehensive income (loss)						

Postretirement medical plan amortization of prior service costs	989	989	989		(1,978)	989
Postretirement medical plan adjustment	(5,564)	(5,564)	(5,564)		11,128	(5,564)
Write-off of prior service costs related to Decker Mine pension	3,183	3,183	3,183	3,183	(9,549)	3,183
Income tax on retiree medical plan and pension adjustments	372	372	372	(1,146)	402	372
Other comprehensive income (loss)	(1,020)	(1,020)	(1,020)	2,037	3	(1,020)
Total comprehensive income (loss)	$ 77,940	$ 39,783	$ 100,587	$ (245)	$ (140,125)	$ 77,940

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Operations and Comprehensive Income

(in thousands)

	Year Ended December 31, 2013					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ 9,535	$ 13	$ 1,374,610	$ 21,474	$ (9,535)	$ 1,396,097
Costs and expenses						
Cost of product sold (exclusive of depreciation, depletion, amortization and accretion, shown separately)		87	1,113,988	22,243		1,136,318
Depreciation and depletion		2,679	102,329	(4,485)		100,523
Accretion			11,328	4,014		15,342
Derivative financial instruments			(25,611)			(25,611)
Selling, general and administrative expenses	9,570	728	52,302		(9,535)	53,066
Other operating costs		3,067	1,010			4,077
Total costs and expenses	9,570	6,561	1,255,346	21,772	(9,535)	1,283,715
Operating income (loss)	(35)	(6,548)	119,264	(298)		112,382
Other income (expense)						
Interest income		440				440
Interest expense		(39,410)	(1,890)	(365)		(41,665)
Tax agreement benefit (expense)	(10,515)					(10,515)
Other, net	(226)	(395)	2,516	529		2,423
Total other income (expense)	(10,741)	(39,365)	626	164		(49,317)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	(10,776)	(45,914)	119,890	(134)		63,065
Income tax benefit (expense)	3,850	15,645	(32,473)	1,348		(11,629)
Earnings from unconsolidated affiliates, net of tax		23	512			535
Earnings (losses) from consolidated affiliates, net of tax	58,898	89,143	1,214		(149,255)	
Net income (loss)	51,971	58,898	89,143	1,214	(149,255)	51,971
Other comprehensive income (loss)						
Postretirement medical plan amortization of prior service	1,775	1,775	1,775		(3,550)	1,775

costs						
Postretirement medical plan adjustment	10,824	10,824	10,824		(21,648)	10,824
Other postretirement plan adjustments	3,199	3,199	3,199	3,199	(9,597)	3,199
Income tax on postretirement medical plan and pension adjustments	(5,616)	(5,616)	(5,616)	(1,185)	12,417	(5,616)
Other comprehensive income (loss)	10,182	10,182	10,182	2,014	(22,378)	10,182
Total comprehensive income (loss)	$ 62,153	$ 69,080	$ 99,325	$ 3,228	$ (171,633)	$ 62,153

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Operations and Comprehensive Income

(in thousands)

	Year Ended December 31, 2012					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ 8,076	$	$ 1,494,597	$ 22,176	$ (8,076)	$ 1,516,772
Costs and expenses						
Cost of product sold (exclusive of depreciation, depletion, amortization and accretion, shown separately)		(12)	1,103,013	29,397		1,132,399
Depreciation and depletion		2,403	89,554	2,618		94,575
Accretion			9,852	3,336		13,189
Derivative financial instruments			(22,754)			(22,754)
Selling, general and administrative expenses	8,076	742	53,808		(8,076)	54,548
Other operating costs			2,949			2,949
Total costs and expenses	8,076	3,133	1,236,422	35,352	(8,076)	1,274,906
Gain on sale of Decker Mine interest						
Operating income (loss)		(3,133)	258,176	(13,176)		241,866
Other income (expense)						
Interest income		1,086				1,086
Interest expense	(312)	(33,963)	(1,991)	(63)		(36,327)
Tax agreement benefit (expense)	29,000					29,000
Other, net			(847)			(847)
Total other (expense) income	28,688	(32,877)	(2,838)	(62)		(7,088)
Income (loss) before income tax provision and earnings from unconsolidated affiliates	28,688	(36,010)	255,337	(13,238)		234,778
Income tax benefit (expense)	(10,578)	32,134	(89,142)	4,972		(62,614)
Earnings from unconsolidated affiliates, net of tax		17	1,539			1,556
Earnings (losses) from consolidated affiliates, net of tax	155,609	159,468	(8,266)		(306,811)	
Net income (loss)	173,720	155,609	159,468	(8,266)	(306,811)	173,720

Other comprehensive income (loss)						
Postretirement medical plan amortization of prior service costs	1,575	1,575	1,575		(3,150)	1,575
Postretirement medical plan adjustment	(4,665)	(4,665)	(4,665)		9,330	(4,665)
Write-off of prior service costs related to Decker Mine pension	204	204	204	204	(612)	204
Income tax on retiree medical plan and pension adjustments	1,039	1,039	1,039	(73)	(2,005)	1,039
Other comprehensive income (loss)	(1,847)	(1,847)	(1,847)	131	3,563	(1,847)
Total comprehensive income (loss)	$ 171,873	$ 153,762	$ 157,621	$ (8,135)	$ (303,248)	$ 171,873

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Balance Sheet

(in thousands)

	December 31, 2014					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS						
Current assets						
Cash and cash equivalents	$	$ 167,532	$ 1,213	$	$	$ 168,745
Accounts receivable			14,161	72,676		86,838
Due from related parties			601,540		(601,313)	227
Inventories, net		6,700	73,103			79,802
Deferred income taxes			21,716		(46)	21,670
Derivative financial instruments			17,111			17,111
Other assets	292	6	9,541			9,840
Total current assets	292	174,238	738,385	72,676	(601,359)	384,233
Noncurrent assets						
Property, plant and equipment, net		6,167	1,582,971			1,589,138
Port access contract rights			53,780			53,780
Goodwill			35,634			35,634
Deferred income taxes		33,926	22,542			56,468
Other assets	1,108,101	1,919,464	26,543		(3,013,443)	40,665
Total assets	$ 1,108,393	$ 2,133,795	$ 2,459,855	$ 72,676	$ (3,614,802)	$ 2,159,918
LIABILITIES AND MEMBER'S EQUITY						
Current liabilities						
Accounts payable	$	$ 1,287	$ 50,679	$ 68	$	$ 52,035
Royalties and production taxes			126,212			126,212
Accrued expenses	6,194	5,318	40,701			52,213
Due to related parties	14,365	520,611		66,337	(601,313)	
Current portion of federal coal lease obligations			63,970			63,970
Other liabilities		46	1,632		(46)	1,632
Total current liabilities	20,559	527,262	283,194	66,405	(601,359)	296,062
Noncurrent liabilities						
Senior notes		498,480				498,480
Asset retirement obligations, net of current portion			216,241			216,241
Accumulated postretirement benefit obligation, net of current portion			50,276			50,276

Other liabilities						11,025						11,025
Total liabilities		20,559		1,025,742		560,736		66,405		(601,359)		1,072,084
Commitments and Contingencies (Note 18)												
Total equity		1,087,834		1,108,053		1,899,119		6,271		(3,013,443)		1,087,834
Total liabilities and equity	$	1,108,393	$	2,133,795	$	2,459,855	$	72,676	$	(3,614,802)	$	2,159,918

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Balance Sheet

(in thousands)

	December 31, 2013					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS						
Current assets						
Cash and cash equivalents	$	$ 226,993	$ 496	$ 4,144	$	$ 231,633
Investments in marketable securities		80,687				80,687
Accounts receivable			12,799	61,269		74,068
Due from related parties			541,997		(541,255)	742
Inventories, net		6,193	70,206	3,745		80,144
Deferred income taxes	4,960		13,372	12	(18)	18,326
Derivative financial instruments			26,420			26,420
Other assets	8,715		10,729	97		19,541
Total current assets	13,675	313,873	676,019	69,267	(541,273)	531,561
Noncurrent assets						
Property, plant and equipment, net		9,301	1,644,679	34		1,654,014
Port access contract rights		9,520				9,520
Goodwill			35,634			35,634
Deferred income taxes	33,087	35,994	10,938	11,342		91,361
Other assets	1,068,318	1,790,738			(2,823,721)	35,335
Total assets	$ 1,115,080	$ 2,159,426	$ 2,367,270	$ 80,643	$ (3,364,994)	$ 2,357,425
LIABILITIES AND MEMBER'S EQUITY						
Current liabilities						
Accounts payable	$	$ 2,378	$ 55,472	$ 1,196	$	$ 59,046
Royalties and production taxes			129,158	2,758		131,917
Accrued expenses	3,245	2,087	35,652	480		41,463
Due to related parties	6,191	489,645		45,419	(541,255)	
Current portion of tax agreement liability	13,504					13,504
Current portion of federal coal lease obligations			58,958			58,958
Other liabilities		72	1,493	966	(18)	2,513
Total current liabilities	22,940	494,182	280,733	50,819	(541,273)	307,401
Noncurrent liabilities						
Tax agreement liability, net of current portion	90,091					90,091

Senior notes		596,974				596,974
Federal coal lease obligations, net of current portion			63,970			63,970
Asset retirement obligations, net of current portion			175,275	70,806		246,081
Accumulated postretirement benefit obligation, net of current portion			38,862			38,862
Other liabilities			23,538	3,142	(14,683)	11,997
Total liabilities	113,030	1,091,156	582,378	124,767	(555,956)	1,355,376
Commitments and Contingencies (Note 18)						
Total equity	1,002,049	1,068,270	1,784,892	(44,124)	(2,809,038)	1,002,049
Total liabilities and equity	$ 1,115,080	$ 2,159,426	$ 2,367,270	$ 80,643	$ (3,364,994)	$ 2,357,425

117

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Cash Flows

(in thousands)

	Year Ended December 31, 2014					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (891)	$ (21,169)	$ 124,642	$ (4,408)	$	$ 98,174
Investing activities						
Purchases of property, plant and equipment		(4,177)	(14,542)			(18,719)
Cash paid for capitalized interest			(4,133)			(4,133)
Investments in marketable securities		(8,159)				(8,159)
Maturity and redemption of investments		88,845				88,845
Investment in port access contract rights			(39,260)			(39,260)
Investment in development projects			(3,522)			(3,522)
Contributions made to subsidiary			(1,750)		1,750	
Distribution received from subsidiary			1,486		(1,486)	
Other		(46)	(1,641)			(1,687)
Net cash provided by (used in) investing activities		76,463	(63,362)		264	13,365
Financing activities						
Principal payments of federal coal leases			(58,958)			(58,958)
Issuance of senior notes		200,000				200,000
Repayment of senior notes		(300,000)				(300,000)
Payment of deferred financing costs		(14,755)				(14,755)
Contributions received from parent				1,750	(1,750)	
Distributions made to parent				(1,486)	1,486	
Other	891		(1,605)			(714)
Net cash provided by (used in) financing activities	891	(114,755)	(60,563)	264	(264)	(174,427)
		(59,461)	717	(4,144)		(62,888)

Net increase (decrease) in cash and cash equivalents						
Cash and cash equivalents at beginning of period		226,993	496	4,144		231,633
Cash and cash equivalents at the end of period	$	$ 167,532	$ 1,213	$	$	$ 168,745

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Cash Flows

(in thousands)

	Year Ended December 31, 2013					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (240)	$ 37,369	$ 149,691	$ (6,080)	$	$ 180,740
Investing activities						
Purchases of property, plant and equipment		(5,085)	(41,692)	(3)		(46,780)
Cash paid for capitalized interest			(33,230)			(33,230)
Investments in marketable securities		(64,357)				(64,357)
Maturity and redemption of investments		64,011				64,011
Investment in port throughput agreement			(2,160)			(2,160)
Investment in development projects			(4,087)			(4,087)
Return of partnership escrow deposit				4,468		4,468
Contributions made to subsidiary			(7,600)		7,600	
Distribution received from subsidiary			4,468		(4,468)	
Other		(21)	126	12		117
Net cash provided by (used in) investing activities		(5,452)	(84,175)	4,477	3,132	(82,018)
Financing activities						
Principal payments of federal coal leases			(63,191)			(63,191)
Payment of deferred financing costs			(1,039)			(1,039)
Contributions received from parent				7,600	(7,600)	
Distributions made to parent				(4,468)	4,468	
Other	240		(790)			(550)
Net cash provided by (used in) financing activities	240		(65,020)	3,132	(3,132)	(64,780)
Net increase (decrease) in cash and cash equivalents		31,917	496	1,529		33,942
Cash and cash equivalents at beginning of period		195,076		2,615		197,691
Cash and cash equivalents at the end of period	$	$ 226,993	$ 496	$ 4,144	$	$ 231,633

Table of Contents

CLOUD PEAK ENERGY INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Condensed Consolidating Statement of Cash Flows

(in thousands)

	Year Ended December 31, 2012					
	Parent Guarantor (CPE Inc.)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (114)	$ 36,458	$ 219,458	$ (8,447)	$	$ 247,355
Investing activities						
coal and land assets			(300,377)			(300,377)
Purchases of property, plant and equipment		(8,175)	(45,185)	(190)		(53,550)
Cash paid for capitalized interest			(50,119)			(50,119)
Investments in marketable securities		(67,576)				(67,576)
Maturity and redemption of investments		62,463				62,463
Investment in port access contract rights			(7,360)			(7,360)
Investment in development projects			(29)			(29)
Return of restricted cash		71,244				71,244
Partnership escrow deposit				(4,470)		(4,470)
Contributions made to subsidiary		(300,377)	(12,570)		312,947	
Distribution received from subsidiary						
Other	49	(47)	1,907			1,909
Net cash provided by (used in) investing activities	49	(242,468)	(413,733)	(4,660)	312,947	(347,865)
Financing activities						
Principal payments of federal coal leases			(102,198)			(102,198)
Contributions received from parent			300,377	12,570	(312,947)	
Other	65		(3,906)			(3,841)
Net cash provided by (used in) financing activities	65		194,273	12,570	(312,947)	(106,039)
Net increase (decrease) in cash and cash equivalents		(206,010)	(2)	(537)		(206,549)
Cash and cash equivalents at beginning of period		401,087	2	3,151		404,240
Cash and cash equivalents at the end of period	$	$ 195,077	$	$ 2,614	$	$ 197,691

Table of Contents

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

None.

Item 9A. ***Controls and Procedures.***

Disclosure Controls and Procedures

An evaluation was performed by management, under the supervision and with the participation of the 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. Our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures, which are designed to provide reasonable assurance that information required to be disclosed in reports filed under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the specified time periods and accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure, were effective at a reasonable assurance level as of December 31, 2014.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed under the supervision of the Chief Executive Officer and Chief Financial Officer, and effected by our Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles.

Because of 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.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework (2013)*. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2014.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited the effectiveness of our internal control over financial reporting as of December 31, 2014, as stated in their audit report included in Part II, Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting

There were no changes in CPE Inc. s internal control over financial reporting during the quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, CPE Inc. s internal control over financial reporting.

Item 9B. ***Other Information.***

None.

Table of Contents

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 Election of Class III Directors in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting and in Part I of this report under the caption Executive Officers. Such information is incorporated herein by reference. The information required by Items 405 and 407(c)(3), (d)(4), and (d)(5) of Regulation S-K will be included under the captions Section 16(a) Beneficial Ownership Reporting Compliance and Corporate Governance in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting and is incorporated herein by reference.

We have adopted a Code of Ethics for Principal Executive and Senior Financial Officers, which is available on our website at www.cloudpeakenergy.com in the Corporate Governance and Committee Charters subsection in the Investor Relations section. We will disclose any future amendments to or waivers from our Code of Ethics for Principal Executive and Senior Financial Officers by posting such information on our website.

Item 11. *Executive Compensation.*

The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K will be included in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting under the caption Executive Compensation and is incorporated herein by reference.

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

The information required by Item 403 of Regulation S-K will be included under the caption Security Ownership of Management and Principal Stockholders in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting and is incorporated herein by reference.

As required by Item 201(d) of Regulation S-K, the following table provides information regarding our equity compensation plans as of December 31, 2014:

Plan Category	**Number of securities to be issued upon exercise of outstanding options, warrants, and rights**	**Weighted -average exercise price of outstanding options, warrants, and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))**

	(a)		(b)	(c)
Equity compensation plans approved by security holders	3,547,585	$	16.80	2,760,121(1)
Equity compensation plans not approved by security holders				
Total	3,547,585	$	16.80	2,760,121(1)

(1) Includes 2,453,372 shares under the Long Term Incentive Plan and 306,749 shares under our Employee Stock Purchase Plan. Shares available for issuance under the Long Term Incentive Plan may be issued pursuant to restricted stock, restricted stock units, options, stock appreciation rights, dividend equivalent rights, performance awards, and share awards.

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

The information required by Item 404 of Regulation S-K will be included under the caption Certain Relationships and Related Party Transactions in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting and is incorporated herein by reference. The information required by Item 407(a) of Regulation S-K will be included under the caption Independence of Directors in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting and is incorporated herein by reference.

Table of Contents

Item 14. ***Principal Accounting Fees and Services.***

The information required by Item 9(e) of Schedule 14A will be included under the caption Independent Auditor Fees and Services in our Proxy Statement to be distributed to our stockholders in connection with our 2015 annual meeting and is incorporated herein by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) *The following documents are filed as part of this Report:*

(1)	Reports of Independent Registered Public Accounting Firm
	Consolidated Balance Sheets as of December 31, 2014 and 2013
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012
	Consolidated Statements of Equity for the Years Ended December 31, 2014, 2013, and 2012
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012
	Notes to Consolidated Financial Statements
(2)	Reserved
(3)	Exhibit List

(b) *Exhibits*

See Exhibit Index at page 125 of this report.

Table of Contents

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.

CLOUD PEAK ENERGY INC.

Date: February 17, 2015

By: /s/ COLIN MARSHALL
Colin Marshall

President and Chief Executive Officer
Principal Executive Officer

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

Name and Signatures	Title	Date
/s/ COLIN MARSHALL **Colin Marshall**	President and Chief Executive Officer *(Principal Executive Officer)*	February 17, 2015
/s/ MICHAEL BARRETT **Michael Barrett**	Executive Vice President and Chief Financial Officer *(Principal Financial Officer)*	February 17, 2015
/s/ HEATH A. HILL **Heath A. Hill**	Vice President and Chief Accounting Officer *(Principal Accounting Officer)*	February 17, 2015
/s/ KEITH BAILEY **Keith Bailey**	*(Chairman of the Board of Directors)*	February 17, 2015
/s/ PATRICK J. CONDON **Patrick J. Condon**	*(Director)*	February 17, 2015
/s/ WILLIAM T. FOX III **William T. Fox III**	*(Director)*	February 17, 2015
/s/ STEVEN W. NANCE **Steven W. Nance**	*(Director)*	February 17, 2015
/s/ WILLIAM F. OWENS **William F. Owens**	*(Director)*	February 17, 2015

Table of Contents

EXHIBIT INDEX

The exhibits below are numbered in accordance with the Exhibit Table of Item 601 of Regulation S-K. The headings below are for convenience only and do not modify in any way the requirements of the Securities and Exchange Commission with regard to exhibits.

Exhibit Number	Description of Documents
	Acquisition Agreements
2.1	Purchase and Sale Agreement, dated as of June 29, 2012, among Arrowhead I LLC, Chevron U.S.A. Inc., CONSOL Energy Inc., Consolidation Coal Company and Reserve Coal Properties Company (Incorporated herein by reference to Exhibit 2.1 to CPE Inc. s Current Report on Form 8-K filed on July 2, 2012 (File No. 001-34547))
2.2	Purchase and Sale Agreement, dated as of June 29, 2012, among Chevron U.S.A. Inc. and Arrowhead I LLC (Incorporated herein by reference to Exhibit 2.2 to CPE Inc. s Current Report on Form 8-K filed on July 2, 2012 (File No. 001-34547))
2.3	Purchase and Sale Agreement, dated as of June 29, 2012, among CONSOL Energy Inc., Consolidation Coal Company, Reserve Coal Properties Company and Arrowhead I LLC (Incorporated herein by reference to Exhibit 2.3 to CPE Inc. s Current Report on Form 8-K filed on July 2, 2012 (File No. 001-34547))
	Corporate Documents
3.1	Amended and Restated Certificate of Incorporation of Cloud Peak Energy Inc. effective as of November 25, 2009 (Incorporated herein by reference to Exhibit 3.1 to CPE Inc. s Annual Report on Form 10-K filed on February 14, 2014 (File No. 001-34547))
3.2	Amended and Restated Bylaws of Cloud Peak Energy Inc. effective as of July 9, 2014 (Incorporated herein by reference to Exhibit 3.1 to CPE Inc. s Current Report on 8-K filed on July 11, 2014 (File No. 001-34547))
4.1	Form of Stock Certificate of Cloud Peak Energy Inc. (Incorporated herein by reference to Exhibit 4.1 to Amendment No. 5 to CPE Inc. s Form S-1 filed on November 16, 2009 (File No. 333-161293))
	Indenture
4.2	Indenture, dated as of November 25, 2009, by and among Cloud Peak Energy Resources LLC (and its subsidiaries listed on the signature page), Cloud Peak Energy Finance Corp., Wilmington Trust Company and Citibank, N.A. (Incorporated herein by reference to Exhibit 4.1 to CPE Inc. s Current Report on Form 8-K filed on December 2, 2009 (File No. 001-34547))
4.3	Form of Exchange Notes (Included in Exhibit 4.2 hereto)
4.4	Fourth Supplemental Indenture, dated as of March 10, 2014, to the Indenture, dated as of November 25, 2009, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., Wilmington Trust Company, as trustee, and Citibank N.A., as securities administrator (Incorporated by reference to Exhibit 4.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on March 11, 2014 (File No. 001-34547))
4.5	Fifth Supplemental Indenture, dated as of March 25, 2014, to the Indenture, dated as of November 25, 2009, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., Wilmington Trust Company, as trustee, and Citibank N.A., as securities administrator (Incorporated by reference to Exhibit 4.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on March 25, 2014 (File No. 001-34547))

Table of Contents

Exhibit Number	Description of Documents
4.6	Indenture, dated as of March 11, 2014, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.2 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on March 11, 2014 (File No. 001-34547))
4.7	First Supplemental Indenture, dated as of March 11, 2014, to the Indenture, dated as of March 11, 2014, among Cloud Peak Energy Resources LLC, Cloud Peak Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.3 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on March 11, 2014 (File No. 001-34547))
	Coal Leases
10.1	Federal Coal Lease WYW-151643: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.2	Federal Coal Lease WYW-141435: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.3	Federal Coal Lease WYW-0321780: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.4	Federal Coal Lease WYW-0322255: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.4 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.5	Federal Coal Lease WYW-163340: Antelope Coal LLC (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on July 1, 2011 (File No. 001-34547))
10.6	Federal Coal Lease WYW-177903: Antelope Coal LLC (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on August 12, 2011 (File No. 001-34547))
10.7	State of Wyoming Coal Lease No. 0-26695: Antelope Coal Mine (Incorporated herein by reference to Exhibit 10.5 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.8	Federal Coal Lease WYW-8385: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.6 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.9	Federal Coal Lease WYW-23929: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.7 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.10	Federal Coal Lease WYW-174407: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.8 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.11	Federal Coal Lease WYW-154432: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.9 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.12	State of Wyoming Coal Lease No. 0-26935-A: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.10 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.13	State of Wyoming Coal Lease No. 0-26936-A: Cordero-Rojo Mine (Incorporated herein by reference to Exhibit 10.11 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.14	Federal Coal Lease MTM-88405: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.12 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.15	Modified Federal Coal Lease MTM-069782: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on June 18, 2010 (File No. 001-34547))

10.16	Federal Coal Lease MTM-94378: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.14 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.17	State of Montana Coal Lease No. C-1101-00: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.15 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))

Table of Contents

Exhibit Number	Description of Documents
10.18	State of Montana Coal Lease No. C-1099-00: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.16 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.19	State of Montana Coal Lease No. C-1100-00: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.17 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
10.20	State of Montana Coal Lease No. C-1088-05: Spring Creek Mine (Incorporated herein by reference to Exhibit 10.18 to CPE Inc. s Form S-1 filed on August 12, 2009 (File No. 333-161293))
	IPO Agreements
10.21	Master Separation Agreement, dated as of November 19, 2009, by and among Cloud Peak Energy Inc., Cloud Peak Energy Resources LLC, Rio Tinto America Inc., Rio Tinto Energy America Inc. and Kennecott Management Services Company (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on November 25, 2009 (File No. 001-34547))
10.22	Management Services Agreement, dated as of November 19, 2009, by and between Cloud Peak Energy Inc. and Cloud Peak Energy Resources LLC (Incorporated herein by reference to Exhibit 10.9 to CPE Inc. s Current Report on Form 8-K filed on November 25, 2009 (File No. 001-34547))
10.23	Acceleration and Release Agreement, dated August 19, 2014, between Cloud Peak Energy Inc. and Rio Tinto Energy America Inc. (Incorporated by reference to Exhibit 10.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on August 20, 2014 (File No. 001-34547))
	Credit Agreements
10.24	Credit Agreement, dated as of February 21, 2014, by and among Cloud Peak Energy Resources LLC (and its subsidiaries listed on the signature page), PNC Bank, National Association, as administrative agent, and a syndicate of lenders (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on February 21, 2014 (File No. 001-34547))
10.25	First Amendment to Credit Agreement, dated September 5, 2014, between Cloud Peak Energy Resources LLC, the guarantors party thereto, the lenders party thereto and PNC Bank, National Association, as Administrative Agent (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on September 21, 2014 (File No. 001-34547))
10.26	Guarantee and Security Agreement, dated as of February 21, 2014, by and between Cloud Peak Energy Resources LLC (and its subsidiaries listed on the signature page) and PNC Bank, National Association (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on September 21, 2014 (File No. 001-34547))
10.27	Security Agreement Supplement, dated as of March 11, 2014, between Cloud Peak Energy Inc. and PNC Bank, National Association, as administrative agent (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Quarterly Report on 10-Q filed on April 30, 2014 (File No. 001-34547))
	Receivables Agreements
10.28	Receivables Purchase Agreement, dated as of February 11, 2013, by and between Cloud Peak Energy Resources LLC, Cloud Peak Energy Receivables LLC, PNC Bank, National Association, as administrator, and various conduit purchasers (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on February 13, 2013 (File No. 001-34547))
10.29	First Amendment to Receivables Purchase Agreement, dated as of September 20, 2013, by and among Cloud Peak Energy Receivables LLC, Cloud Peak Energy Resources LLC, Market Street Funding LLC, PNC Bank, National Association, as administrator, and various conduit purchasers (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Quarterly Report on Form 10-Q filed on October 30, 2013 (File No. 001-34547))

Table of Contents

Exhibit Number	Description of Documents
10.30	Second Amendment to Receivables Purchase Agreement, dated as of January 23, 2015, by and among Cloud Peak Energy Receivables LLC, Cloud Peak Energy Resources LLC, PNC Bank, National Association, as administrator, and various conduit purchasers (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on January 23, 2015 (File No. 001-34547))
	LTIP
10.31	Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.32 to Amendment No. 5 to CPE Inc. s Form S-1 filed on November 16, 2009 (File No. 333-161293))
10.32	Amendment No. 1 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 14, 2011 (File No. 001-34547))
10.33	Amendment No. 2 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on May 20, 2011 (File No. 001-34547))
10.34	Amendment No. 3 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on May 20, 2011 (File No. 001-34547))
10.35	Amendment No. 4 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan, dated as of April 10, 2014 (Incorporated herein by reference to Exhibit 10.7 to CPE Inc. s Quarterly Report on Form 10-Q filed on April 30, 2014 (File No. 001-34547))
10.36*	Amendment No. 5 to the Cloud Peak Energy Inc. 2009 Long Term Incentive Plan, dated as of January 8, 2015
	Forms of LTIP Award Agreements
10.37	Form of Cloud Peak Energy Inc. 2009 Long Term Incentive Plan IPO Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.33 to Amendment No. 5 to CPE Inc. s Form S-1 filed on November 16, 2009 (File No. 333-161293))
10.38	Form of 2011 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 9, 2011 (File No. 001-34547))
10.39	Form of 2011 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on March 9, 2011 (File No. 001-34547))
10.40	Form of 2011 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.48 to CPE Inc. s Annual Report on Form 10-K filed on February 25, 2011 (File No. 001-34547))
10.41	Form of 2012 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 16, 2012 (File No. 001-34547))
10.42	Form of 2012 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on March 16, 2012 (File No. 001-34547))
10.43	Form of 2012 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Restricted Stock Agreement (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Current Report on Form 8-K filed on March 16, 2012 (File No. 001-34547))
10.44*	Form of 2012 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement

Table of Contents

Exhibit Number	Description of Documents
10.45	Form of 2013 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Performance Share Unit Award Agreement (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 11, 2013 (File No. 001-34547))
10.46	Form of 2013 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Nonqualified Stock Option Agreement (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on Form 8-K filed on March 11, 2013 (File No. 001-34547))
10.47	Form of 2013 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Current Report on Form 8-K filed on March 11, 2013 (File No. 001-34547))
10.48	Form of 2013 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement (Incorporated herein by reference to Exhibit 10.44 to CPE Inc. s Annual Report on Form 10-K filed on February 14, 2013 (File No. 001-34547))
10.49	Form of 2014 Performance Share Unit Award Agreement under the 2009 Cloud Peak Energy Inc. Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on 8-K filed on March 14, 2014 (File No. 001-34547))
10.50	Form of 2014 Nonqualified Stock Option Agreement under the 2009 Cloud Peak Energy Inc. Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Current Report on 8-K filed on March 14, 2014 (File No. 001-34547))
10.51	Form of 2014 Restricted Stock Unit Agreement under the 2009 Cloud Peak Energy Inc. Long Term Incentive Plan (Incorporated herein by reference to Exhibit 10.3 to CPE Inc. s Current Report on 8-K filed on March 14, 2014 (File No. 001-34547))
10.52*	Form of 2014 Cloud Peak Energy Inc. 2009 Long Term Incentive Plan Director Restricted Stock Unit Agreement
	Annual Incentive Plan
10.53	Cloud Peak Energy Inc. 2013 Annual Incentive Plan (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on May 15, 2013 (File No. 001-34547))
	Deferred Compensation Plan
10.54	Form of Deferred Compensation Plan for Cloud Peak Energy Resources LLC (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Current Report on Form 8-K filed on March 22, 2011 (File No. 001-34547))
10.55	First Amendment to the Cloud Peak Energy Resources LLC Deferred Compensation Plan (Incorporated herein by reference to Exhibit 10.47 to CPE Inc. s Annual Report on Form 10-K filed on February 14, 2013 (File No. 001-34547))
10.56	Second Amendment to the Cloud Peak Energy Resources LLC Deferred Compensation Plan (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Quarterly Report on Form 10-Q filed on October 30, 2013 (File No. 001-34547))
	ESPP
10.57	Amended and Restated Employee Stock Purchase Plan dated October 3, 2013 (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Quarterly Report on Form 10-Q filed on October 30, 2013 (File No. 001-34547))
	Employment Agreements
10.58	Employment Agreement between Cloud Peak Energy Inc. and Colin Marshall dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.40 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))

Table of Contents

Exhibit Number	Description of Documents
10.59	Employment Agreement between Cloud Peak Energy Inc. and Michael Barrett dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.41 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.60	Employment Agreement between Cloud Peak Energy Inc. and Gary Rivenes dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.43 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.61	Employment Agreement between Cloud Peak Energy Inc. and James Orchard dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.44 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.62	Employment Agreement between Cloud Peak Energy Inc. and Cary Martin dated as of November 14, 2009 (Incorporated herein by reference to Exhibit 10.45 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.63	Employment Agreement between Cloud Peak Energy Inc. and Bryan Pechersky dated as of March 3, 2010 (Incorporated herein by reference to Exhibit 10.46 to CPE Inc. s Annual Report on Form 10-K filed on March 17, 2010 (File No. 001-34547))
10.64	Employment Agreement between Cloud Peak Energy Inc. and Todd A. Myers dated as of July 6, 2010 (Incorporated herein by reference to Exhibit 10.2 to CPE Inc. s Quarterly Report on Form 10-Q filed on August 5, 2010 (File No. 001-34547))
10.65	Employment Agreement between Cloud Peak Energy Inc. and Bruce Jones dated as of July 8, 2013 (Incorporated herein by reference to Exhibit 10.1 to CPE Inc. s Quarterly Report on Form 10-Q filed on July 31, 2013 (File No. 001-34547))
	Other Exhibits
10.66	Agreement, dated August 7, 2014, between Cloud Peak Energy Logistics LLC and Coal Valley Resources, Inc. (incorporated by reference to Exhibit 10.1 to Cloud Peak Energy Inc. s Current Report on Form 8-K filed on August 8, 2014 (File No. 001-34547))
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm
23.2*	Consent of J.T. Boyd Company
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95.1*	Mine Safety Disclosure
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Presentation Linkbase Document

101.DEF*	XBRL Taxonomy Definition Document

* Filed or furnished herewith, as applicable

Management contract or compensatory plan or arrangement