CLOUD PEAK ENERGY INC.
Form 10-K
March 15, 2019
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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, 2018

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.)
748 T-7 Road, Gillette, Wyoming (Address of principal executive offices)	**82718** (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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No 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, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.:

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o
	Emerging growth company o

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

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 29, 2018, the last business day of Cloud Peak Energy Inc. s most recently completed second fiscal quarter, the aggregate market value of the voting and non-voting common stock held by non-affiliates of Cloud Peak Energy Inc. was approximately $256 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 $3.49 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, 76,507,272 shares outstanding as of March 8, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

Documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

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CLOUD PEAK ENERGY INC.

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

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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, similar words. 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, divestitures, or other transactions. 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:

- substantial doubt about our ability to continue as a going concern;

- our need to restructure our balance sheet, which may require us to sell assets, restructure our debt, or seek protection under Chapter 11 of the U.S. Bankruptcy Code (Chapter 11);

- our ability to maintain, obtain and comply with the terms of required surety bonds;

- the terms and restrictions of our indebtedness;

- our level of indebtedness;

- liquidity constraints, access to capital and credit markets and availability and costs of credit, surety bonds, letters of credit, and insurance, including risks resulting from the cost or unavailability of financing due to debt and equity capital and credit market conditions for the coal sector or in general, changes in our credit rating, our compliance with the covenants in our debt agreements, the credit pressures on our industry due to depressed conditions, and demands for increased collateral by our surety bond providers;

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

- current and future expenses incurred in connection with our evaluation of the restructuring of our balance sheet and any resulting transactions;

- our ability to attract and retain key personnel;

- our ability to comply with the restrictions imposed by our A/R Securitization Program and other financing arrangements;

- the timing and extent of any sustained recovery of the currently depressed PRB thermal coal industry and the impact of ongoing or further depressed PRB thermal coal industry conditions on our financial performance, liquidity, and any financial covenant compliance;

- 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 resulting in decreased long-term purchases of coal;

- the timing of reductions or increases in customer coal inventories;

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- our ability to obtain new coal sales agreements on favorable terms, to resolve customer requests for reductions or deferrals of coal deliveries, and to respond to any cancellations of their committed volumes on terms that preserve the amount and timing of our forecasted economic value;

- the impact of increasingly variable and less predictable demand for thermal coal based on natural gas prices, summer cooling demand, winter heating demand, economic growth rates, and other factors that impact overall demand for electricity;

- our ability to comply with minimum production requirements under our coal leases and avoid advanced royalty obligations;

- our ability to efficiently and safely conduct our mining operations and to adjust our planned production levels to respond to market conditions and effectively manage the costs of our operations;

- competition with other producers of coal and with traders and re-sellers of coal, including the current oversupply of thermal coal, the impacts of currency exchange rate fluctuations and the strong U.S. dollar, and government environmental, energy and tax policies and regulations that make foreign coal producers more competitive for international transactions;

- the impact of coal industry bankruptcies on our competitive position relative to other companies who have emerged from bankruptcy with reduced leverage and potentially reduced operating costs;

- competition with natural gas, wind, solar, and other non-coal energy resources, which may continue to increase as a result of low domestic natural gas prices, the declining cost of renewables and due to environmental, energy and tax policies, regulations, subsidies, and other government actions that encourage or mandate use of alternative energy sources;

- coal-fired power plant capacity and utilization, including the impact of climate change and other environmental regulations and initiatives, energy policies, political pressures, NGO activities, international treaties or agreements 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 coal from the PRB;

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

- the impact of "keep coal in the ground" campaigns and other well-funded, anti-coal initiatives by environmental activist groups and others targeting substantially all aspects of our industry;

- our ability to offset declining U.S. demand for coal and achieve longer term growth in our business through our logistics revenue and export sales, including the significant impact of Chinese and Indian thermal coal import demand and production levels from other countries and basins on overall seaborne coal prices;

- the impact of any "trade wars" on our export business;

- railroad, export terminal and other transportation performance, costs and availability, including the availability of sufficient and reliable rail capacity to transport PRB coal, any development of future export terminal capacity and our ability to access capacity on commercially reasonable terms;

- the impact of our rail and terminal take-or-pay commitments if we do not meet our required export shipment obligations;

- weather conditions and weather-related damage that impact our mining operations, our customers, or transportation infrastructure, including the adverse impact on our costs and production volumes of the heavy rain experienced during the second quarter of 2018, particularly at our Antelope Mine;

- operational, geological, equipment, permit, labor, and other risks inherent in surface coal mining;

- future development or operating costs for our development projects exceeding our expectations or other factors adversely impacting our development projects;

- our ability to successfully acquire coal and appropriate land access rights at economic prices and in a timely manner and our ability to effectively resolve issues with conflicting mineral development that may impact our mine plans;

- the impact of additional 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;

- the impact of current and future environmental, health, safety, endangered species and other laws, regulations, treaties, executive orders, court decisions or governmental policies, or changes in interpretations thereof and third-party regulatory challenges, including additional requirements, uncertainties, costs, liabilities or restrictions adversely affecting the use, demand or price for coal, our mining operations or the logistics, transportation, or terminal industries;

- the impact of required regulatory processes and approvals to lease coal and obtain, maintain, and renew permits for coal mining operations or to transport coal to domestic and foreign customers, including third-party legal challenges to regulatory approvals that are required for some or all of our current or planned mining activities;

- 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 and our assumptions underlying reclamation and mine closure obligations;

- the availability of, disruptions in delivery or increases in pricing from third-party vendors of raw materials, capital equipment and 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 any credit agreement and financial institutions with whom we maintain accounts or enter hedging arrangements;

- the results of our hedging programs and changes in the fair value of derivative financial instruments that are not accounted for as hedges;

- volatility and recent declines in the price of our common stock, including the impact of any delisting of our stock from the NYSE if we fail to cure our noncompliance with the minimum average closing price listing standard;

- litigation and other contingencies;

- the authority of federal and state regulatory authorities to order any of our mines to be temporarily or permanently closed under certain circumstances; and

- other risk factors or cautionary language described from time to time in the reports and registration statements we file with the SEC, including those in Item 1A of this Form 10-K.

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GLOSSARY FOR SELECTED TERMS

Amended Credit Agreement. Our revolving credit agreement with PNC Bank, National Association, as administrative agent, and a syndicate of lenders, as amended and restated on May 24, 2018, which was terminated effective November 15, 2018.

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.

A/R Securitization Program. Our accounts receivable securitization program.

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. coalfields 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).

CAA. Clean Air Act.

CAIR. Clean Air Interstate Rule.

CEQ. Council on Environmental Quality.

CO_2. 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.

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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.

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.

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 SO_2/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.

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NAAQS. National Ambient Air Quality Standards.

NEPA. National Environmental Policy Act.

NGO. Non-governmental organization.

NO_x. Nitrogen oxides. NO_x 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 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.

Northern PRB. The area within the PRB that lies within Montana and the northern part of Sheridan County, Wyoming.

NYSE. New York Stock Exchange.

ONRR. Department of the Interior, Office of Natural Resources Revenue.

QSO. Qualified Surface Owner. A status attributed by the BLM to a certain class of surface owners of split estate lands, which allow 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 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. Both state and federal laws closely regulate reclamation.

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 that operate to control sulfur compounds formed during coal combustion. An example of a scrubber is a flue gas desulfurization unit.

SEC. Securities and Exchange Commission.

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 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.

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.

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.

U.S. GAAP. Accounting principles generally accepted in the United States of America.

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PART I

Item 1. *Business.*

Overview

We produce coal in the PRB. 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 own and operate three surface coal mines: the Antelope Mine, the Cordero Rojo Mine, and the Spring Creek Mine.

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. Thermal coal is primarily consumed by electric utilities and industrial consumers as fuel for electricity generation. In 2018, the coal we produced generated approximately 2% of the electricity produced in the U.S. As of December 31, 2018, we controlled approximately 977.3 million tons of proven and probable reserves. We do not produce any metallurgical coal. See Item 1 Business Mining Operations.

In addition, we have two development projects, both located in the Northern PRB. The Youngs Creek project is an undeveloped surface mine project located in Wyoming, seven miles south of our Spring Creek Mine and contiguous with the Wyoming-Montana state line. The Big Metal project is located near the Youngs Creek project on the Crow Indian Reservation in southeast Montana. On June 7, 2018, Big Metal Coal Co. LLC (Big Metal), our wholly-owned subsidiary, delivered notice to the Crow Tribe of Indians (Crow Tribe) to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. These two projects, in addition to the exercise of the aforementioned options, are described in more detail under Item 1 Business Development Projects. Any future development and coal production from these projects remains subject to significant risks and uncertainty. These development projects have been impaired. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

Our logistics business provides a variety of services designed to facilitate the sale and delivery of coal, primarily to Asian utility customers. 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 port agreements and demurrage settlement with vessel operators. See Item 1. Business Transportation and Logistics Services for further discussion.

Recent Developments

During the fourth quarter of 2018 and through the filing date of this Form 10-K, we made a number of announcements regarding Cloud Peak Energy s engagement of various advisors to assist in reviewing alternatives including the potential sale of the Company and to assist in reviewing our capital structure and strategic restructuring alternatives. During that time, we experienced a number of adverse events that have negatively impacted our financial results, liquidity and future prospects. Our business and liquidity outlook has been adversely impacted since the third quarter of 2018 by a number of factors, which are highlighted in this Recent Developments section:

- operational issues in the fourth quarter of 2018 at our Antelope mine;
- depressed PRB thermal coal industry conditions;
- logistics export pricing declined in the fourth quarter of 2018 to an uneconomic level;
- reduced cash flow projections for 2019 and future years;
- termination of our Credit Agreement due to significantly reduced availability and the impact of the financial covenants;
- significantly reduced liquidity, primarily comprised of our cash and cash equivalents;
- reduced A/R Securitization Program availability, requiring greater cash collateralization;

- noncompliance with the NYSE s continued listing requirements and potential delisting of our common stock;

- demands for additional reclamation surety bond collateral;

- our election not to make an interest payment under the 2024 Notes (as defined below) on the March 15, 2019 due date, utilizing the grace period provided by the indenture; and

- our continued review of our capital structure and restructuring alternatives.

As a result of the developments noted above, asset impairments were recorded as of December 31, 2018, and there was a determination of substantial doubt in our ability to continue as a going concern, based on current projections. This Recent Developments section highlights these events and should be read together with the rest of this Form 10-K, including without limitation, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 1A Risk Factors and Item 8 Financial Statements and Supplementary Data.

Fourth Quarter Operational Issues at Antelope Mine

In the fourth quarter of 2018, we experienced continued production issues at our Antelope Mine resulting from weather-related spoil failures due to heavy 2018 rains and related events**.** The rehandle of material by our truck and shovel fleets increased the per ton costs during the fourth quarter of 2018. This activity deferred the planned pre-stripping work into 2019, thereby increasing the projected costs for 2019 to regain a proper mine sequence. For additional discussion and analysis about the adverse effects from these production issues at our Antelope Mine in the fourth quarter of 2018, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

Fourth Quarter Logistics Pricing Decline

In the fourth quarter of 2018, export prices for our logistics business declined significantly. From September 30, 2018 to December 31, 2018, the Kalimantan index declined by 14 percent from $53.25 per tonne to $46.00 per tonne. At this reduced price, our logistics business did not generate positive economic returns as reflected by the loss in our Logistics and Related Activities segment during the fourth quarter of 2018 and lowered our forecasted 2019 expectations. This was a significant difference from the September 30, 2018 pricing and economics.

Reduced Cash Flow Projections for 2019

During 2018, our cash balance decreased by $16.7 million because our cash flows from operations were insufficient to fund our cash interest and capital expenditures during the year. This large decrease in cash occurred during the fourth quarter of 2018 as our cash balance decreased from $109.5 million as of September 30, 2018 to $91.2 million as of December 31, 2018.

Further, as our business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, our updated financial forecasts reflected significantly lower levels of expected cash flow from operating activities for 2019. The forecasting updates reflected the ongoing production issues at our Antelope Mine, resulting from the spoil failure re-handling described above, which requires significant deferred pre-stripping costs to be incurred in 2019 and lower export pricing assumptions.

Additionally, we experienced lower customer demand overall, particularly for the 8400 Btu coal from our Cordero Rojo Mine, as evidenced by lower contracted volumes and prices. As a result of the decline of the weighted average realized price at the Cordero Rojo Mine from 2018 to 2019, and rising costs caused by higher strip ratios, the cash margins and cash flow projections for 2019 sales at Cordero Rojo are uneconomic. This lower demand also resulted in reduced planned production rates at the Cordero Rojo Mine as part of our 2019 budgeting process that was completed in 2019.

For additional discussion and analysis, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

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Termination of Credit Facility

As disclosed in our Current Report on Form 8-K on November 13, 2018, Cloud Peak Energy Resources LLC (CPE Resources), a wholly owned subsidiary of CPE, provided PNC Bank, National Association with notice to terminate the Credit Agreement. The termination of the Credit Agreement was effective as of November 15, 2018. As of September 30, 2018, the $150 million Credit Agreement had a reduced availability of only $16.2 million of borrowing capacity based upon the quarterly financial covenant calculations. Any failure to meet those financial covenants could have resulted in an event of default under the Credit Agreement and cross-default under the indentures governing our senior notes. The Credit Agreement would have required CPE Resources to pay over $3.0 million in additional commitment and administrative fees during the remaining term of the Credit Agreement through May 2021, which will now be avoided. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Significantly Reduced Liquidity

Subsequent to the termination of the Credit Agreement, our liquidity was comprised of cash and cash equivalents, because the A/R Securitization Program was fully utilized to issue letters of credit as collateral for the reclamation surety bond providers. As of December 31, 2018, our total available liquidity was $91.2 million. As of March 8, 2019, our total available liquidity was $65.5 million, and we expect to continue using additional cash that will further reduce this liquidity.

Reduced Accounts Receivable Securitization Program Availability

Our A/R Securitization Program allows for the issuance of letters of credit. As of December 31, 2018, the A/R Securitization Program would have allowed for $21.3 million of borrowing capacity, which was less than the undrawn face amount of letters of credit outstanding under the A/R Securitization Program of $25.7 million as of December 31, 2018. The $4.4 million difference between the borrowing capacity and the undrawn face amount of the letters of credit outstanding was cash-collateralized into a restricted cash account in early January 2019, thus bringing the borrowing capacity to zero. As of March 8, 2019, the A/R Securitization Program would have allowed for $13.5 million of borrowing capacity, which is less than the $25.7 million in outstanding indebtedness under the A/R Securitization Program. The difference has been cash collateralized. For additional information, see Note 18 of Notes to Consolidated Financial Statements in Item 8.

Noncompliance with the NYSE s Continued Listing Requirements

As disclosed in our Current Report on Form 8-K on December 27, 2018, we were notified by the NYSE that the average closing price of shares of our common stock had fallen below $1.00 per share over a period of 30 consecutive trading days, which is the minimum average share price for continued listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. Under the NYSE s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. Since that time, our share price has continued to trade well under $1.00.

Demands for Additional Reclamation Surety Bond Collateral

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. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program as well as restricted cash, securing coal lease obligations, and for other operating requirements.

Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. Any further issuances of letters of credit to satisfy the increased collateral demands or any replacement bonds would immediately reduce the cash and cash equivalents available to support the operations of the business, as the current level of letters of credit exceeds the borrowing credit limit of our A/R Securitization Program. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiations will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our mining operations.

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Fourth Quarter Asset Impairments

As a result of the aforementioned changes experienced in the fourth quarter of 2018 and the outlook for the business going forward, we recorded asset impairments as of December 31, 2018 with respect to (1) our Cordero Rojo mine and (2) our Youngs Creek and Big Metal development projects.

Our Cordero Rojo Mine produces 8400 Btu coal, and it is experiencing a strip ratio increase at a time of sustained low customer demand. As 2019 and future business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, a triggering event was identified which required impairment assessment for which the conclusion was that an impairment was determined to exist as of December 31, 2018. The carrying net book value amount related primarily to land access and mineral rights, and was impaired by $372.4 million. The asset impairment charge does not alter the underlying land access and mineral rights. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

In addition, we have two development projects, both located in the Northern PRB, the Youngs Creek and Big Metal projects. As 2019 and future business plans and financial forecasts were updated and reviewed during the fourth quarter of 2018 and finalized in the first quarter of 2019, it became evident that, along with the lack of access to the capital markets, the business would not be able to generate the capital required to develop these projects. It was concluded that a triggering event existed, and the fair value was determined to be less than the carrying value, requiring the recognition of an impairment as of December 31, 2018. The carrying net book value amount, which related primarily to land access and mineral rights, was reduced by $309.2 million. The asset impairment charge does not alter the underlying land access and mineral rights. An improved future outlook could provide the opportunity to reassess the potential development of these projects. For additional information, see Note 7 of Notes to Consolidated Financial Statements in Item 8.

Election Not to Make an Interest Payment under the 2024 Notes

As of December 31, 2018 and March 11, 2019, CPE Resources had $290.4 million in outstanding indebtedness under the 12.00% second lien senior notes due 2021 (the   2021 Notes) and $56.4 million in outstanding indebtedness under the 6.375% senior notes due 2024 (the   2024 Notes , and collectively with the 2021 Notes, the   senior notes).

CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, which is due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. Although we have sufficient liquidity to make the interest payment, we elected not to make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

CPE Resources has an interest payment obligation under the 2021 Notes of approximately $17.4 million, which is due on May 1, 2019. The indenture governing the 2021 Notes provides a 30-day grace period that extends the latest date for making this interest payment to May 31, 2019, before an Event of Default occurs under the indenture. If we do not make this interest payment by May 31, 2019, an Event of Default would occur under the indenture governing the 2021 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2021 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2021 Notes. An Event of Default under the 2021 Notes for failure to pay interest would not result in a default under the 2024 Notes unless the 2021 Notes are accelerated. An Event of Default under the 2021 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance.

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Ability to Continue as a Going Concern

Our reduced liquidity, most notably with the termination of our Credit Agreement in November 2018 due to the limited availability thereunder based on the financial covenants, along with our forecasts projecting lower levels of operating cash flow have limited our access to the capital markets. Our liquidity is now limited to cash and cash equivalents. Our forecasted cash from operations alone is insufficient to fund cash interest and capital expenditures. This has resulted in our conclusion that there is substantial doubt about our ability to continue as a going concern. As a result, we will continue to pursue options to alleviate this condition, including but not limited to evaluating our restructuring options, but there can be no guarantees that this will alleviate the substantial doubt that exists. Our consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. As a result, the accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of assets and their carrying amounts, or the amount and classification of liabilities that may result should we be unable to continue as a going concern.

On March 14, 2019, we entered into a Forbearance Agreement (the Forbearance Agreement) by and among Cloud Peak Energy Receivables LLC, CPE Resources and PNC Bank, National Association, as administrator, relating to our A/R Securitization Program, which provides that PNC Bank, National Association will not exercise any of its remedies upon a default under the A/R Securitization Program based on the existence of substantial doubt regarding our ability to continue as a going concern. Pursuant to the Forbearance Agreement, the forbearance period terminates on the earlier of (i) April 14, 2019 and (ii) the date on which any additional events of default may occur, as specified therein.

Review of Capital Structure and Restructuring Alternatives

As disclosed in our Current Report on Form 8-K on November 13, 2018, we announced a Strategic Alternatives Review. Our Board of Directors, working together with its management team and legal and financial advisors, has commenced a review of strategic alternatives, including a potential sale of the Company. We engaged J.P. Morgan Securities LLC as our financial advisor and Allen & Overy LLP as our legal counsel in connection with our review of strategic alternatives. This fourth quarter 2018 process did not result in a transaction.

As disclosed on our Current Report on Form 8-K on January 29, 2019, we issued a press release providing an update to the previously-announced review of strategic alternatives, announcing the retention of Centerview Partners LLC as our investment banker, Vinson & Elkins LLP as our legal advisor, and FTI Consulting, Inc. as our financial advisor to assist us in our review of capital structure and restructuring alternatives.

Our restructuring evaluation process is continuing. We are actively engaged in discussions with certain of our creditor groups financial and legal advisors regarding potential alternatives, including asset sales, a private debt restructuring, or a court-supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code, and related financing needs. Although this process remains uncertain and fluid, we will need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity and continue as a going concern. As noted above, an interest payment on our 2024 Notes will need to be made by April 14, 2019, to avoid a default under the indenture governing the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment. If we determine not to make this interest payment by April 14, 2019, we may seek protection under Chapter 11.

In connection with our review of capital structure and restructuring alternatives, we expect our mining operations and reclamation activities to continue in the ordinary course of business.

As a result of our ongoing restructuring evaluation, we currently expect to delay our 2019 annual stockholders meeting.

Segment Information

Our reportable segments include Owned and Operated Mines and Logistics and Related Activities. For a discussion on these segments, please see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations as well as Note 5 of Notes to Consolidated Financial Statements in Item 8.

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, a Delaware limited liability company formed on August 19, 2008. Between 1993 and 1998, our predecessor acquired the Antelope Mine, Spring Creek Mine, the Cordero Rojo Mine, and a 50% non-operating interest in the Decker Mine. On September 12, 2014, we sold our 50% interest in the Decker Mine to an affiliate of Ambre Energy North America, Inc. (Ambre Energy), now known as Lighthouse Resources Inc.

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% interest in CPE Resources until December 15, 2010, when CPE Inc. priced a secondary offering of its common stock on behalf of Rio Tinto (the Secondary Offering). In connection with the Secondary Offering, CPE Inc. exchanged shares of its common stock for common membership units of CPE Resources held by Rio Tinto, resulting in our acquisition of 100% of Rio Tinto s holdings 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 95% or more.

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.

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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 customers 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.

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, 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 U.S. coal customers on the Great Lakes for blending by the customer with coal sourced from other locations 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. 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, 2018.

	2018 As Delivered Average				Tons Sold		
Mine	**Btu per lb**	**Ash Content (%)**	**Sulfur Content (%)**	**(lbs SO2/mmBtu)**	**2018**	**2017 (million tons)**	**2016**
Antelope	8,851	5.64	0.23	0.52	23.2	28.4	29.8
Cordero Rojo	8,436	5.29	0.29	0.69	12.6	16.4	18.3
Spring Creek	9,252	5.37	0.33	0.72	13.9	12.6	10.4
Other (1)	N/A	N/A	N/A	N/A		0.3	0.3
Total					49.7	57.8	58.8

(1) 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.

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. See Item 2 Properties Reserve Acquisition Process. Based on the average sulfur content of 0.50 lbs SO_2/mmBtu, the reserves at our Antelope Mine are considered 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. Significant additional areas of unleased coal are potentially available for nomination by us or other mining operations or persons adjacent to our current operations. See Item 2 Properties Reserve Acquisition Process. Based on the average sulfur content of 0.66 lbs SO_2/mmBtu, the reserves at our Cordero Rojo Mine are considered compliance coal under the Clean Air Act.

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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. During the years ended December 31, 2018, 2017, and 2016, we shipped approximately 4.6, 4.2, and 0.6 million tons, respectively, of Spring Creek coal through the Westshore terminal located in British Columbia, Canada. Based on the average sulfur content of 0.73 lbs SO_2/mmBtu, the reserves at our Spring Creek Mine are considered compliance coal under the Clean Air Act.

Development Projects

Youngs Creek Project

The Youngs Creek project, an undeveloped surface mine project in the Northern PRB region, is located in Wyoming, approximately 13 miles north of Sheridan, Wyoming, seven miles south of our Spring Creek Mine and seven miles from the mainline railroad, contiguous with the Wyoming-Montana state line. It is near the Big Metal 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. We have not been able to classify the Youngs Creek project mineral rights as proven and probable reserves as they remain subject to further exploration and evaluation based on market conditions. The Youngs Creek project mining permit covers 283.6 million tons of non-reserve coal deposits, of which approximately 267 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 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.

Big Metal Project

In January 2013, Big Metal entered into an option agreement and a corresponding exploration agreement with the Crow Tribe. These agreements were approved by the U.S. Department of the Interior in June 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. The option and exploration agreements provided for exploration rights and exclusive options to lease three separate coal deposits on the Crow Indian Reservation over an initial five-year term, which would have expired June 14, 2018, with two extension periods through 2035 if certain conditions were met. On June 7, 2018, Big Metal delivered notice to the Crow Tribe to exercise the Upper Youngs Creek coal lease option and extend the coal lease options for the Squirrel Creek and Tanner Creek project areas. In connection with the option exercise and option extensions, Big Metal paid approximately $1.8 million to the Crow Tribe in June 2018. Since inception of the option agreement, Big Metal has made option and lease bonus payments totaling approximately $12 million to the Crow Tribe, including the option exercise payments in June 2018. The coal lease will still require approval from the U.S. Department of the Interior and related regulatory actions before it is effective. Exercise of the Upper Youngs Creek option and payment of the initial option payments for the Squirrel Creek and Tanner Creek project areas triggered the commencement of the first option extension periods for Squirrel Creek and Tanner Creek through December 31, 2025.

Upon the exercise of an option or options to lease, we 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 Big Metal project is similar quality to that of our Spring Creek Mine and offers lower sodium levels. We have completed the exploration program for the Big Metal project and are evaluating the development options for this project. We believe that the proximity of the Big Metal project to the Spring Creek Mine and the Youngs Creek project represents an opportunity to optimize our mine developments in the Northern PRB.

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Any future development and coal production from these projects remains subject to significant risk and uncertainty.

The map below shows where the Youngs Creek project and Big Metal project (Squirrel Creek, Tanner Creek, and Upper Youngs Creek coal deposits) are located relative to our Spring Creek Mine.

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(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 or may not be converted to future reserves of the company.

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 46 domestic and foreign electric utilities and over 85% of our sales were to customers with an investment grade credit rating as of December 31, 2018. Furthermore, 84% of our 2018 sales were to customers with whom we have had relationships for more than 10 years. During 2018, approximately 53% of our consolidated revenue was derived from our top ten customers. No customer accounted for 10% or more of our total revenue in 2018, 2017, or 2016.

Coal produced approximately 27% of electricity generation in the U.S. through October 2018. The following map shows the percentage of our tons sold by state of destination during 2018 from coal produced at the three mines we own and operate. Our coal supplies fueled approximately 2% of the electricity generated in the U.S. in 2018. Approximately 9% of the tons produced at our mines were sold to customers outside of the U.S. in 2018.

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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 typically 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. 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.

Mine Customers

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 historically featured terms of one to five years, although recent trends have been toward sales with shorter terms, including monthly and quarterly contracts. This has led to greater variability and less long-term predictability of our sales. For the year ended December 31, 2018, approximately 81% of our revenue was derived from supply contracts with terms of one year or greater.

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 sales agreements 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 sales agreements 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 our customer contracts 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 within specified ranges 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 sales agreements. Some customers are allowed to vary the amount of coal taken under the contract. Most of our coal sales agreements 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, suspension or cancellation of shipments or termination of the contracts. 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.

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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 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 sales agreements, we agree to indemnify or reimburse our customers for damage to their or their rail carrier s equipment resulting from our negligence, and for damage to their equipment due to non-coal materials being included with our coal before leaving our property.

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 typically 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 Antelope and Cordero Rojo mines are served by the BNSF and UP railroads. Our Spring Creek Mine is served solely by the BNSF railroad.

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

Coal Sales Agreements

We generally enter into binding contracts that are fixed-price, fixed-volume supply contracts with our domestic logistics customers. Contracts with these 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 our international logistics customers, we often enter into contracts that contain multi-year terms with future year pricing to be agreed upon, meaning that there is an expectation of sales, provided that mutual agreement on pricing can be reached. This is consistent with conventional industry standards for sales into the Asian Pacific region. Our Asian delivered shipments are typically 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, as published by Global Coal and others, and the Platts Kalimantan 5000. The Newcastle benchmark price is an established index for high Btu Australian bituminous thermal coal available to be loaded on a vessel at a coal terminal near Newcastle, north of Sydney. The Kalimantan 5000 is an established index for subbituminous Indonesian thermal coal. Our delivered sales have historically priced at a range between 60% to 75% of the forward Newcastle price and at a smaller discount to the forward Kalimantan 5000 price due to quality and freight cost differentials. In late 2018, the collapse of the Indonesian rupiah lowered producers U.S. Dollar cost and the Indonesian Government removed export restrictions to increase U.S. Dollar exports. The result has been an increase in Indonesian exports and a drop in the Kalimantan 5000 index. The current wide gap between Newcastle and Kalimantan 5000 index pricing is not common compared to historical spreads.

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

- demurrage fees for international contracts, charged to us when a vessel is not dispatched in the agreed-upon time;
- fixed pricing for the current year of sales, and a provision providing for future years   pricing to be negotiated by a specific point in time for 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 port agreements and demurrage settlements with vessel operators. We also bear the costs of transporting the coal to the delivery point. For our international customers, this generally means that we cover the costs associated with an export terminal located in the Pacific Northwest. Our logistics customers located overseas are generally responsible for paying the cost of ocean freight, although occasionally we may arrange or be responsible for the cost of 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 customers and demand, 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. We have similar arrangements in certain other Asian countries.

To help support and ensure export terminal capacity for export sales, we enter into multi-year 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 still obligated to make payments to the export terminal company or railroad. See Item 7   Management s Discussion and Analysis of Financial Condition and Results of Operations   Contractual Obligations   for more detail. 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.

Historical Westshore and BNSF Logistics Agreements

In 2011, we entered into a multi-year throughput contract with Westshore Terminals Limited Partnership (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, 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 October 2015, we announced an amended agreement with Westshore whereby the previously committed volumes for 2016 through 2018 were reduced to zero in exchange for an upfront payment made in October 2015, plus quarterly payments during 2016 through 2018, as specified in the amended agreement. In December 2015, we announced a similar amendment to our transportation agreement with BNSF.

In November 2016, due to the improvement in export coal prices, we entered into agreements with Westshore and BNSF to ship coal during the fourth quarter of 2016. These agreements were effective for the fourth quarter of 2016 only, and did not change the aforementioned amended agreements discussed above, or the terms of the previous throughput or transportation agreements. Under the fourth quarter agreements, we received a partial credit against current charges for the quarterly payments made under the previous agreements.

At December 31, 2016, we terminated our previous agreement with Westshore and entered into a new agreement. In February 2017, we terminated our previous agreement with BNSF and entered into a new agreement effective in April 2017. The new agreements provided for shipments in 2017 and 2018 and required minimum payments for those two years. We had the right to terminate our commitments at any time in exchange for buyout payments.

Current Westshore and BNSF Logistics Agreements

On December 28, 2017, we extended our agreement with Westshore through the end of 2020. We further amended this agreement in July 2018 to extend through the end of 2022 and allow for greater capacity in 2021 and 2022 to 10.5 million total annual throughput tons. We retain the right to terminate our commitments at any time in exchange for a buyout payment. The buyout payment amount varies throughout the period based upon an agreed schedule. Additionally, after the new Westshore agreement terminates and through 2024, if we choose to ship to export customers, we are required to offer to ship through Westshore up to a specified annual tonnage on terms similar to the new agreement before shipping through any other export terminal. Westshore has the right to accept or reject our offer in its sole discretion. See Note 6 of Notes to Consolidated Financial Statements in Item 8 for further discussion regarding the accounting treatment of these transactions.

We signed an agreement with BNSF on January 9, 2018, extending the existing agreement through the end of 2020. We have the right to terminate our commitments for the remaining years at any time in exchange for buyout payments. We are currently in discussions with BNSF regarding an extension through December 2022 to support our increased port capacity for our Asian export business.

Other Logistics Agreements

In addition to our current port agreement with Westshore, we hold an option contract to increase our future export capacity through the proposed Millennium Bulk Terminals (MBT) coal export facility in Washington State. The timing and outcome of the permit process related to MBT, and therefore the construction of the terminal, is uncertain.

We also previously had a minority ownership interest in the joint venture that was seeking to develop Gateway Pacific Terminal (GPT) in Washington State. SSA Marine, the majority interest holder and project developer, notified us of its intention to no longer pursue a coal terminal. As a result, in January 2017, we abandoned our ownership interest in the joint venture, and we no longer have any ownership interest or associated funding obligations for the joint venture. We continue to have residual contractual rights as a potential customer of the terminal if the project is resumed in a designated period of time in the future. The abandonment of our interest in GPT had no effect on our financial statements since we fully impaired our investment in 2015.

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 years ended December 31, 2018, 2017, and 2016, we purchased and resold 0.0, 0.3, and 0.3 million tons, respectively, 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 and after sales service;

- Logistics, which provides logistical and additional contract support to our domestic customers, and also 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 March 8, 2019, we had 9 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 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, with traders and re-sellers of coal and with producers of natural gas and other competing energy sources may continue to negatively affect our sales volumes and our ability to sell coal at a favorable price.* We compete with other coal producers, with traders and re-sellers of coal and 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 and with traders and re-sellers of coal 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 weather and economic conditions, the supply and demand for domestic and foreign electricity, domestic and foreign governmental regulations and taxes, environmental and other regulatory changes, global climate change initiatives, 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 the U.S. federal government owns most of the coal in the vicinity of our mines, we compete with other coal producers operating in the PRB for additional coal through the competitive LBA process.

Employees

As of March 8, 2019, we had approximately 1,300 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 March 8, 2019, we had approximately 150 external contractors on a full-time, equivalent basis.

Executive Officers

The information required by Item 401 of Regulation S-K is included in Part III, Item 10 of this report.

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

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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, orders, or treaties, including those relating to global climate change, may continue to cause coal to become a less attractive fuel source, thereby further 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. See also Note 21 of Notes to Consolidated Financial Statements in Item 8 for a discussion regarding certain challenges by environmental activist groups against various regulatory processes impacting our mines. 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. As discussed in more detail in Surety Bonds below, mine operators must also provide financial assurance to ensure performance of the reclamation plan and to guarantee long-term obligations. Typically, we submit the 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.

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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.

From time to time, OSM will also update its mining regulations under SMCRA. For example, in December 2016, the OSM published a final rule to revise its regulations related to protecting streams and related wildlife from adverse impacts of surface coal mining operations. The rule would have imposed stricter guidelines on conducting coal mining operations within buffer zones; required mine operators to collect additional baseline data about the site of the proposed mining operation and adjacent areas; imposed additional surface and groundwater monitoring requirements; enacted specific requirements for the protection or restoration of perennial and intermittent streams; and imposed additional bonding and financial assurance requirements. In February 2017, the rule was revoked pursuant to the Congressional Review Act. Accordingly, the rule has no force or effect and cannot be replaced by a similar rule absent future legislation. This type of rule or other new SMCRA regulations could result in additional material costs, obligations, and restrictions associated with our operations.

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 2018, 2017, and 2016 we recorded $13.8 million, $16.1 million, and $16.3 million, respectively, of expense related to these reclamation fees.

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. At some point, federal and state laws may be amended to require certain forms of financial assurance that are more costly to obtain. Recently, there has been heightened regulatory pressure on reclamation bonding and self-bonding in particular. We exited self-bonding in the first quarter of 2017. 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. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program used for mining, securing coal lease obligations, and for other operating requirements. For additional discussion and recent developments regarding our surety bonds, please see Recent Developments .

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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 (previously acquired by 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. For example, the second phase of the MSHA s respirable coal mine dust rule went into effect in February 2016, and requires increased sampling frequency and the use of continuous personal dust monitors. In August 2016, the third and final phase of the rule became effective, reducing the overall respirable dust standard in coal mines from 2.0 to 1.5 milligrams per cubic meter of air. Our compliance with these or any other 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. Nevertheless, if we were to be found in violation of mine safety and health regulations, we could face penalties or restrictions that may materially and adversely impact our operations, financial results and liquidity.

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 2018, 2017, and 2016 we recorded $22.6 million, $26.4 million, and $28.6 million, respectively, 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 to help cover the cost of present and future claims through the use of trusts or insurance policies. We may also be liable under state laws for black lung claims that are covered through insurance policies.

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Clean Air Act

The 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 materially and adversely affect our operations, financial results, liquidity, and demand for our coal, 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.

- *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. The EPA has determined that the areas in which we operate are classified under the new nitrogen oxide standard as unclassifiable/attainment . Based on the EPA s third round of area designations, no areas in which we operate have been designated as nonattainment under the 2010 revised sulfur dioxide NAAQS. In November 2015, the EPA also revised the NAAQS for ground level ozone to a stricter, lower standard of 70 parts per billion. The EPA completed area designations for the 2015 ozone standards in July 2018.

- *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. In September 2016, the EPA finalized an update to the CSAPR ozone season program by issuing the Final CSAPR Update. 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 State Implementation Plan 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 U.S. Court of Appeals for the D.C. Circuit upheld various portions of the rulemaking in two separate decisions issued in March and April 2014, respectively. In June 2015, the U.S. Supreme Court struck down the MATS rule based on the EPA s failure to take costs into consideration and remanded the case back to the D.C. Circuit. The D.C. Circuit has remanded the rule to the EPA, but allowed the current rule to stay in place until the EPA issues a new finding. In April 2016, the EPA issued a final finding that it is appropriate and necessary to set standards for emissions of air toxics from coal- and oil-fired power plants. In December 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS rule proposing to determine that it is not appropriate and necessary to regulate Hazardous Air Pollutant (HAP) emissions from power plants under Section 112 of the Clean Air act. The EPA is not proposing, however, to rescind or repeal the HAP emission standards and other requirements of the MATS rule. 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 further decrease the demand for coal. Like CSAPR, MATS and other similar future regulations could accelerate the retirement of a significant number of coal-fired power plants, in addition to the significant number of plants and units that have already been retired as a result of environmental and regulatory requirements and uncertainties adversely impacting coal-fired generation. Such retirements would adversely impact our business.

- *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. In January 2014, the EPC promulgated a final rule partially disapproving the Wyoming Regional Haze State Implementation Plan (SIP). The state of Wyoming and others challenged the final rule. After mediated discussions through the U.S. Court of Appeals for the Tenth Circuit s Mediation Office, Basin Electric, Wyoming and the EPA reached a settlement in 2017. In April 2018, the state of Wyoming submitted a SIP revision in accordance with the terms of the settlement. The EPA proposed to approve the revision in October 2018 and also proposed revisions to the state of Wyoming s Federal Implementation Plan (FIP) in accordance with the terms of the 2017 settlement.

- 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

Global climate change initiatives and public perceptions regarding fossil fuels have resulted, and are expected to continue to result, in decreased coal-fired power plant capacity and utilization, phasing out and closing many existing coal-fired power plants, reducing or eliminating construction of new coal-fired power plants in the United States and certain other countries, increased costs to mine coal and decreased demand and prices for thermal coal, including PRB coal.

There are three important sources of GHGs associated with the coal industry. The end use of our coal in electricity generation is the largest of the three sources 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 subject to pending and proposed regulation as part of initiatives to address global climate change.

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. Most recently, the United Nations Framework Convention on Climate Change met in Paris, France in December 2015 and agreed to an international climate agreement. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. The Paris climate agreement entered into force in November 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the U.S. to withdraw from the agreement, with the earliest possible effective date of withdrawal being November 4, 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. These commitments could further reduce demand and prices for our coal.

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.

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.

In August 2015, the EPA issued its final Clean Power Plan (CPP) rules that establish carbon pollution standards for power plants, called CO_2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the United States Court of Appeals for the District of Columbia (Circuit Court) even issued a decision. By its terms, this stay will remain in effect throughout the pendency of the appeals process including at the Circuit Court and the Supreme Court through any certiorari petition that may be granted. The Supreme Court s stay applies only to EPA s regulations for CO_2 emissions from existing power plants and will not affect EPA s standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In August 2018, EPA issued the proposed

Affordable Clean Energy (ACE) Rule, which would replace the CPP. If the ACE Rule is finalized, it will likely be subject to judicial challenge. If the effort to repeal or replace the CPP is unsuccessful and the rules were upheld at the conclusion of the appellate process and were implemented in their current form, or if the ACE Rule results in state plans to reduce the level of GHG emissions from electric utility generating units, demand for coal would likely be further decreased, potentially significantly, and our business would be adversely impacted.

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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, or related public perceptions regarding climate change, are expected to require additional controls on coal-fired power plants and industrial boilers and may cause some users of coal to further switch from coal to alternative sources of fuel, thereby depressing demand and pricing for coal.

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. Congress has also considered legislation that seeks to clarify the scope of CWA jurisdiction. Recent court decisions, regulatory actions and proposed legislation have created uncertainty over CWA jurisdiction and permitting requirements.

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 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 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 January 2017. The new NWP 21 closely mirrors the 2012 NWP 21, but removes a provision authorizing disposal of dredged or fill material from certain surface coal mining activities that were previously authorized by the 2007 NWP 21 and clarifies that any losses of stream bed are applied to the 1/2-acre limit for loss of jurisdictional wetlands and waters. 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.

- Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the Clean Water Act. A 2015 rulemaking by

EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a United States District Court in North Dakota. In January 2018, the Supreme Court determined that the circuit courts do not have jurisdiction to hear challenges to the 2015 rule, removing the basis for the Sixth Circuit to continue its nationwide stay. In February 2018, the EPA and the Corps published a final rule extending the applicability date of the 2015 rule such that the rule would not be applicable until February 2020. In August 2018, the U.S. District Court for the District of South Carolina invalidated the two-year nationwide delay of the rule, leaving the 2015 rule in effect in 26 states, while the pre-2015 regulations and guidance continue to apply in 24 states. In December 2018, the EPA and the Corps proposed a new definition of waters of the United States . Judicial challenges to the 2015 rulemaking are likely to continue to work their way through the courts along with challenges to the more recent rulemaking extending the applicability date of the 2015 rule. The agencies efforts to repeal the 2015 rule and to revise the definition of waters of the United States will also likely be subject to lengthy judicial challenges. For now, EPA and the Corps are complying with the South Carolina District Court s order in the 26 states in which it applies. Should the 2015 rule be enforced in the states in which we operate, or should a different rule expanding the definition of what constitutes a water of the United States be finalized as a result of EPA and the Corps s rulemaking process we, could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

- *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 adversely 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. For example, in December 2016, Congress passed the Water Infrastructure Improvements for the Nation Act, which allows states to establish permit programs to regulate the disposal of CCR units in lieu of the EPA s CCR regulations. 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 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 further 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. These liabilities could be significant and materially and adversely impact our financial results and liquidity.

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.

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 Mine applied for a lease modification under the BLM leasing regulations and a mine permit amendment to add lands to the permit area. Portions of these lands have been designated as core habitat for the greater sage grouse by the Montana Fish, Wildlife and Parks Department. While the USFWS has determined that the greater sage grouse should not be listed as a threatened or endangered species, the BLM has developed Conservation Plans designed to preserve and protect greater sage-grouse habitat. Montana has also developed sage grouse conservation plans through the Montana Governor s executive order. Our approvals to mine or otherwise affect these areas will be subject to review by the BLM and the Montana Department of Environmental Quality and determinations of our ability to adequately mitigate impacts to sage grouse and sage grouse habitat. The plans do however, recognize the right to mine where there are valid existing rights. The BLM has stated that conserving sagebrush habitat will be an important consideration in the BLM review of proposed coal mines or coal mine expansions. The plans also recommended that the Secretary of the Interior withdraw 10 million acres from hardrock mining for up to 20 years; however in 2017 the BLM canceled its Sagebrush Focal Area withdrawal application and the Department of the Interior s proposed withdrawal of 10 million acres of federal lands from location and entry under the mining law in the Greater Sage-grouse habitat. The BLM also terminated the associated environmental analysis process. Our mines are not located within the areas that the BLM had designated for withdrawing from hardrock mining.

Future actions could result in more stringent requirements being issued by the BLM and other agencies involved in the leasing and permitting process. The USFWS must review its 2015 decision to not list the sage grouse again in 2020. 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.

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 that 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 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. OSM has not yet issued a proposed rule to address these blasts, and it is unclear if or when a proposed rule will be issued. The outcome of these rulemakings could materially adversely impact our cost or ability to conduct our mining operations.

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 our mining costs and 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 Substances 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.

Federal Power Act   Grid Reliability Proposal

Pursuant to a directive from the Secretary of the Department of Energy, in 2017, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking under the Federal Power Act regarding the valuation by regional electric grid system operators of the reliability and resilience attributes of electricity generation. The rulemaking would have required the FERC to impose market rules that would allow certain cost recovery by electricity-generating units that maintain a 90-day fuel supply on-site and that are therefore capable of providing electricity during supply disruptions from emergencies, extreme weather or natural or man-made disasters. Many coal-fired electricity generating plants could have qualified under this criteria and the cost recovery could have helped improve the economics of their operations. However, in January 2018, the FERC terminated the proposed rulemaking, finding that it failed to satisfy the legal requirements of section 206 of the Federal Power Act, and initiated a new proceeding to further evaluate whether additional FERC action regarding resilience is appropriate. Should a version of this rule be adopted along the lines originally proposed, it could provide economic incentives for companies that produce electricity from coal, among other fuels, which could either slow or stabilize the trend in retiring coal-fired power plants and could thereby maintain certain levels of domestic demand for coal. We cannot speculate on the timing or nature of any subsequent FERC or grid operator actions resulting from FERC s decision to further study the issue of grid resiliency.

Available Information

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

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: 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.

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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 Indebtedness and Liquidity

We need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity and continue as a going concern. Our potential restructuring alternatives include asset sales, a private debt restructuring or a court-supervised restructuring proceeding under Chapter 11 of the U.S. Bankruptcy Code. Alternatively, an involuntary petition for bankruptcy may be filed against us. Any of these restructuring alternatives could have a material adverse impact on our business, financial condition, results of operations, and cash flows and could place our stockholders at significant risk of losing all of their investment in our shares.

As disclosed on our Current Report on Form 8-K on January 29, 2019, we issued a press release providing an update to the previously-announced review of strategic alternatives, announcing the retention of Centerview Partners LLC as our investment banker, Vinson & Elkins LLP as our legal advisor, and FTI Consulting, Inc. as our financial advisor to assist us in our review of capital structure and restructuring alternatives.

Our restructuring evaluation process is continuing. We are actively engaged in discussions with certain of our creditor groups financial and legal advisors regarding potential alternatives, including asset sales, a private debt restructuring or a court-supervised reorganization under Chapter 11 of the U.S. Bankruptcy Code and related financing needs. Although this process remains uncertain and fluid, we will need to restructure our balance sheet in order to improve our capital structure, adjust our business to ongoing depressed PRB thermal coal industry conditions, address our significantly reduced liquidity, and continue as a going concern.

An interest payment on our 2024 Notes will need to be made by April 14, 2019, to avoid a default under the indenture governing the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment. If we determine not to make this interest payment by April 14, 2019, we may seek protection under Chapter 11.

A bankruptcy proceeding could have a material adverse effect on our business, financial condition, results of operations and liquidity. It is impossible for us to predict with certainty the amount of time needed to complete a Chapter 11 proceeding. For as long as a Chapter 11 proceeding were to continue, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization as well as focusing on our business operations. A lengthy Chapter 11 proceeding would involve significant additional professional fees and expenses, and create significant liquidity needs for our business. A bankruptcy proceeding also could make it more difficult to retain management and other key personnel necessary to the success of our business. In addition, while we are in a bankruptcy proceeding, our customers and suppliers may lose confidence in our ability to reorganize our business successfully and could seek to establish other commercial relationships, particularly if the process is prolonged. Any bankruptcy proceeding or restructuring may cause, among other things:

- third parties to lose confidence in our ability to deliver coal on time and at specification, resulting in a significant decline in our revenues, profitability and cash flow;

- difficulty retaining, attracting or replacing key employees;

- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and

- our third-party surety bond providers, suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

Additionally, all of our indebtedness is senior to the existing common stock in our capital structure. As a result, if we seek relief under Chapter 11, we believe that our shares of existing common stock would likely be canceled, with a very limited recovery or no recovery for holders of our common stock. And, if we execute a

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restructuring outside of Chapter 11, we believe that such transaction could result in substantial dilution of our shares of existing common stock.

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

As of December 31, 2018, we had consolidated indebtedness of $349.3 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; future LBAs; 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 any future credit agreement 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, including competitors who have become less leveraged when they emerged from bankruptcy;

- 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

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

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. 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, restructure our debt, seek protection under Chapter 11, sell assets, limit certain capital expenditures, including future 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. 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.

Additionally, CPE Resources has an interest payment obligation under the 2024 Notes of approximately $1.8 million, which is due on March 15, 2019. The indenture governing the 2024 Notes provides a 30-day grace period that extends the latest date for making this interest payment to April 14, 2019, before an Event of Default occurs under the indenture. We elected not to make this interest payment on the due date and plan to utilize the 30-day grace period provided by the indenture, to allow additional time to assess our restructuring alternatives. If we do not make this interest payment by April 14, 2019, an Event of Default would occur under the indenture governing the 2024 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2024 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2024 Notes. An Event of Default under the 2024 Notes for failure to pay interest would not result in a default under the 2021 Notes unless the 2024 Notes are accelerated. An Event of Default under the 2024 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance. We continue to evaluate alternatives associated with this interest payment.

CPE Resources has an interest payment obligation under the 2021 Notes of approximately $17.4 million, which is due on May 1, 2019. The indenture governing the 2021 Notes provides a 30-day grace period that extends the latest date for making this interest payment to May 31, 2019, before an Event of Default occurs under the indenture. If we do not make this interest payment by May 31, 2019, an Event of Default would occur under the indenture governing the 2021 Notes, which would give the trustee or the holders of at least 25% of principal amount of the 2021 Notes the option to accelerate maturity of the principal, plus any accrued and unpaid interest, on the 2021 Notes. An Event of Default under the 2021 Notes for failure to pay interest would not result in a default under the 2024 Notes unless the 2021 Notes are accelerated. An Event of Default under the 2021 Notes for failure to pay interest, at the end of the grace period, would result in a cross-default under our A/R Securitization Program and permit the lender to terminate the A/R Securitization Program. In the event of a default and acceleration, we do not have adequate liquidity to repay the principal balance.

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

Upon the occurrence of certain transactions constituting a   change of control   as defined in the indentures, 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. This provision could make it more difficult or more expensive for a third party to acquire us.

As a result of ongoing depressed PRB thermal coal industry conditions and previous coal producer bankruptcy filings, the coal industry has experienced increased credit pressures that could result in additional demands for credit support by third parties or decisions by banks, surety bond providers, investors or other companies to reduce or eliminate their exposure to the coal industry, including our company. These credit pressures could materially and adversely impact our liquidity and ability to meet our regulatory requirements.

Ongoing depressed PRB thermal coal industry conditions and previous coal producer bankruptcy filings have resulted in, and could result further in, increased credit pressures on the coal industry. These credit pressures, which have had a material impact on our business, include, for example, (a) vendors, suppliers, customers and other commercial counterparties seeking prepayments, security deposits, letters of credit and other credit protections, and (b) banks, surety bond providers, investors and other companies reducing or eliminating their exposure to the coal industry. Although some of these credit pressures may be company-specific, many are directed to the coal industry in general due to the current overall negative investor sentiment toward the industry. Any credit demands by third parties or refusals by banks, surety bond providers, investors or others to extend, renew or refinance credit on commercially reasonable terms may adversely impact our business, financial condition, results of operations, cash flows and liquidity. In some cases, such as any collateral requirements imposed by surety bond providers to issue surety bonds that secure our future performance under various federal and state laws, our ability to meet regulatory requirements may also be adversely impacted if we

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are not able to satisfy cash or other collateral requirements. As of December 31, 2018, we had $407.6 million of reclamation and lease bonds backed by collateral of $25.7 million in the form of letters of credit under our A/R Securitization Program used for mining, securing coal lease obligations, and for other operating requirements. Subsequent to December 31, 2018, we received letters from certain of our third-party surety bond underwriters demanding increased collateral or replacement of their bonds. Any further issuances of letters of credit to satisfy the increased collateral demands or any replacement bonds would immediately reduce the cash and cash equivalents available to support the operations of the business, as the current level of letters of credit exceeds the borrowing credit limit of our A/R Securitization Program. We are currently in discussions with our surety bond underwriters, however we cannot assure you these negotiations will be successful in avoiding increased collateral requirements. These surety bonds are required by the permits governing our m