HALLADOR ENERGY CO
Form 10-K
March 10, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

x ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: **December 31, 2016** OR

¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001-3473

“COAL KEEPS YOUR LIGHTS ON"COAL KEEPS YOUR LIGHTS ON”

HALLADOR ENERGY COMPANY

(www.halladorenergy.com)

Colorado	84-1014610
(State of incorporation)	(IRS Employer Identification No.)

1660 Lincoln Street, Suite 2700, Denver, Colorado	80264-2701
(Address of principal executive offices)	(Zip Code)

Issuer's telephone number: 303.839.5504

Securities registered pursuant to Section 12(b) of the Exchange Act: NONE

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, $.01 par value

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 þ

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

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 and 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 þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. o

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

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

o Large accelerated filer	þ Accelerated filer
o Non-accelerated filer (do not check if a small reporting company)	o Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

The aggregate market value of the common stock held by non-affiliates (public float) on June 30, 2016 was $64 million based on the closing price reported that date by the NASDAQ of $4.62 per share.

As of March 9, 2017, we had 29,412,799 shares outstanding.

Portions of our information statement to be filed with the SEC in connection with our annual stockholders' meeting are incorporated by reference into Part III of this Form 10-K. Our Annual Meeting of Shareholders will be held on May 25, 2017 in Indianapolis, Indiana.

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K may constitute “forward-looking statements.” These statements are based on our beliefs as well as assumptions made by, and information currently available to us. When used in this document, the words “anticipate,” “believe,” “continue,” “estimate,” “expect,” “forecast,” “may,” “project,” similar expressions identify forward-looking statements. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings and sources of funding are forward-looking statements. These statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- changes in competition in coal markets and our ability to respond to such changes;
- changes in coal prices, which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;
- legislation, regulations, and court decisions and interpretations thereof, including those relating to the environment, mining, miner health and safety and health care;
- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- dependence on significant customer contracts, including renewing customer contracts upon expiration of existing contracts;
- changing global economic conditions or in industries in which our customers operate;
- liquidity constraints, including those resulting from any future unavailability of financing;
- customer bankruptcies, cancellations or breaches to existing contracts, or other failures to perform;
- customer delays, failure to take coal under contracts or defaults in making payments;
- adjustments made in price, volume or terms to existing coal supply agreements;
- fluctuations in coal demand, prices and availability;
- our productivity levels and margins earned on our coal sales;
- changes in raw material costs;
- changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;
- increases in labor costs, adverse changes in work rules, or cash payments or projections associated with post-mine reclamation and workers’ compensation claims;
- increases in transportation costs and risk of transportation delays or interruptions;
- operational interruptions due to geologic, permitting, labor, weather-related or other factors;
- risks associated with major mine-related accidents, such as mine fires, or interruptions;
- results of litigation, including claims not yet asserted;
- difficulty maintaining our surety bonds for mine reclamation;
- the coal industry’s share of electricity generation, including as a result of environmental concerns related to coal mining and combustion and the cost and perceived benefits of other sources of electricity, such as natural gas, nuclear energy and renewable fuels;
- uncertainties in estimating and replacing our coal reserves;
- a loss or reduction of benefits from certain tax deductions and credits;

- difficulty obtaining commercial property insurance;
- difficulty in making accurate assumptions and projections regarding future revenue and costs associated with equity investments in companies we do not control; and
- other factors, including those discussed in “Item 1A. Risk Factors.”

2

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in "Item 1A. Risk Factors" below. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the U.S. Securities and Exchange Commission ("SEC"); our press releases; our website ***http://www.halladorenergy.com*** and written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

ITEM 1. BUSINESS.

See Item 7- MDA for a discussion of our business.

Regulation and Laws

The coal mining industry is subject to extensive regulation by federal, state and local authorities on matters such as:

- employee health and safety;
- mine permits and other licensing requirements;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws or that, if spilled, could reach waterways or wetlands;
- plant and wildlife protection;
- reclamation and restoration of mining properties after mining is completed;
- discharge of materials;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and
- the effects, if any, that mining has on groundwater quality and availability.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which has adversely affected demand for coal. It is possible that new legislation or regulations may be adopted, or that existing laws or regulations may be interpreted differently or more stringently enforced, any of which could have a significant impact on our mining operations or our customers' ability to use coal. For more information, please see risk factors described in "Item 1A. Risk Factors" below.

We are committed to conducting mining operations in compliance with applicable federal, state and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of the Mine Safety and Health Administration ("MSHA") where citations can be issued without regard to fault, and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to be free of citations. When we receive a citation, we attempt to remediate any identified condition immediately. While we have not quantified all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Capital expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based upon permit requirements and the costs and timing of asset retirement obligations and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if these accruals were insufficient.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. Applications for permits require extensive engineering and data analysis and presentation and must address a variety of environmental, health and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use and disposal of waste and other substances and impacts on the environment, the construction of water containment areas, and reclamation of the area after coal extraction. Meeting all requirements imposed by any of these authorities may be costly and time-consuming, and may delay or prevent commencement or continuation of mining operations.

The permitting process for certain mining operations can extend over several years and can be subject to administrative and judicial challenge, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. We cannot assure you that we will not experience difficulty or delays in obtaining mining permits in the future or that a current permit will not be revoked.

We are required to post bonds to secure performance under our permits. Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws and regulations described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations that have outstanding environmental violations. Although like other coal companies, we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Mine Health and Safety Laws

Stringent safety and health standards have been imposed by federal legislation since the Federal Coal Mine Health and Safety Act of 1969 ("CMHSA") was adopted. The Federal Mine Safety and Health Act of 1977 ("FMSHA"), and regulations adopted pursuant thereto, significantly expanded the enforcement of health and safety standards of the CMHSA, and imposed extensive and detailed safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations, and numerous other matters. MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, the states where we operate have state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal mining industry are perhaps the most comprehensive and rigorous system in the U.S. for protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in all of the areas in which we operate are subject to the same laws and regulations.

The FMSHA has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without fault, and FMSHA requires imposition of a civil penalty for each cited violation. Negligence and gravity assessments, and other factors can result in the issuance of various types of orders, including orders requiring withdrawal from the mine or the affected area, and some orders can also result in the imposition of civil penalties. The FMSHA also contains criminal liability provisions. For example, criminal liability may be imposed upon corporate operators who knowingly and willfully authorize, order or carry out violations of the FMSHA, or its mandatory health and safety standards.

The Federal Mine Improvement and New Emergency Response Act of 2006 ("MINER Act") significantly amended the FMSHA, imposing more extensive and stringent compliance standards, increasing criminal penalties and establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, MSHA has issued new or more stringent rules and policies on a variety of topics, including:

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training, and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;
- training and availability of mine rescue teams;
- underground "refuge alternatives" capable of sustaining trapped miners in the event of an emergency;
- flame-resistant conveyor belts, fire prevention and detection, and use of air from the belt entry; and
- post-accident two-way communications and electronic tracking systems.

MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards.

In 2014, MSHA began implementation of a finalized new regulation titled "Lowering Miner's Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors." The final rule implements a reduction in the allowable respirable coal mine dust exposure limits, requires the use of sampling data taken from a single sample rather than an average of samples, and increases oversight by MSHA regarding coal mine dust and ventilation issues at each mine, including the approval process for ventilation plans at each mine, all of which increase mining costs The second phase of the rule began in February 2016 and requires additional sampling for designated and other occupations using the new continuous personal dust monitor technology, which provides real-time dust exposure information to the miner. Phase three of the rule began in August 2016 and resulted in lowering the current respirable dust level of 2.0 milligrams per cubic meter to 1.5 milligrams per cubic meter of air. Compliance with these rules can result in increased costs on our operations, including, but not limited to, the purchasing of new equipment and the hiring of additional personnel to assist with monitoring, reporting, and recordkeeping obligations.

Additionally, in July 2014, MSHA proposed a rule addressing the "criteria and procedures for assessment of civil penalties." Public commenters have expressed concern that the proposed rule exceeds MSHA's rulemaking authority and would result in substantially increased civil penalties for regulatory violations cited by MSHA. MSHA last revised the process for proposing civil penalties in 2006 and, as discussed above, civil penalties increased significantly. The notice-and-comment period for this proposed rule has closed, and it is uncertain when MSHA will present a final rule addressing these civil penalties.

In January 2015, MSHA published a final rule requiring mine operators to install proximity detection systems on continuous mining machines, over a staggered time frame ranging from November 2015 through March 2018. The proximity detection systems initiate a warning or shutdown the continuous mining machine depending on the proximity of the machine to a miner. MSHA subsequently proposed a rule requiring mine operators to also install proximity detection systems on other types of underground mobile mining equipment. The comment period for this proposed rule will close on April 10, 2017.

Subsequent to passage of the MINER Act, Illinois, Kentucky, Pennsylvania and West Virginia have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Additionally, state administrative agencies can promulgate administrative rules and regulations affecting our operations. Other states may pass similar legislation or administrative regulations in the future.

Some of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to our customers. Although we have not quantified the full impact, implementing and complying with these new state and federal safety laws and regulations, have had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

The Black Lung Benefits Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981 ("BLBA") requires businesses that conduct current mining operations to make payments of black lung benefits to current and former coal miners with black lung disease and to some survivors of a miner who dies from this disease. The BLBA levies a tax on production of $1.10 per ton for underground-mined coal and $0.55 per ton for surface-mined coal, but not to exceed 4.4% of the applicable sales price, in order to compensate miners who are totally disabled due to black lung disease and some survivors of miners who died from this disease, and who were last employed as miners prior to 1970 or subsequently where no responsible coal mine operator has been identified for claims. In addition, the BLBA provides that some claims for which coal operators had previously been responsible are or will become obligations of the government trust funded by the tax. The Revenue Act of 1987 extended the termination date of this tax from January 1, 1996, to the earlier of January 1, 2014, or the date on which the government trust becomes solvent. We are also liable under state statutes for black lung claims. Congress and state legislatures regularly consider various items of black lung legislation, which, if enacted, could adversely affect our business, results of operations and financial position.

The revised BLBA regulations took effect in January 2001, relaxing the stringent award criteria established under previous regulations and thus potentially allowing new federal claims to be awarded and allowing previously denied claimants to re-file under the revised criteria. These regulations may also increase black lung related medical costs by broadening the scope of conditions for which medical costs are reimbursable and increase legal costs by shifting more of the burden of proof to the employer.

The Patient Protection and Affordable Care Act enacted in 2010, includes significant changes to the federal black lung program, retroactive to 2005, 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.

Workers' Compensation

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment-related deaths. States in which we operate consider changes in workers' compensation laws from time to time.

Surface Mining Control and Reclamation Act

The Federal Surface Mining Control and Reclamation Act of 1977 ("SMCRA") and similar state statutes establish operational, reclamation and closure standards for all aspects of surface mining as well as many aspects of deep mining. Although we have minimal surface mining activity and no mountaintop removal mining activity, SMCRA nevertheless requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of our mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations. We believe we are in compliance in all material respects with applicable regulations relating to reclamation.

In addition, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The tax for surface-mined and underground-mined coal is $0.28 per ton and $0.12 per ton, respectively. We have accrued the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation or orphaned mine sites and acid mine drainage control on a statewide basis.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies that are deemed, according to the regulations, to have “owned” or “controlled” the third-party violator. Sanctions against the “owner” or “controller” are quite severe and can include being blocked from receiving new permits and having any permits revoked that were issued after the time of the violations or after the time civil penalties or reclamation fees became due. We are not aware of any currently pending or asserted claims against us relating to the “ownership” or “control” theories discussed above. However, we cannot assure you that such claims will not be asserted in the future.

The U.S. Office of Surface Mining Reclamation (“OSM”) published in November 2009 an Advance Notice of Proposed Rulemaking, announcing its intent to revise the Stream Buffer Zone (“SBZ”) rule published in December 2008. The SBZ rule prohibits mining disturbances within 100 feet of streams if there would be a negative effect on water quality. Environmental groups brought lawsuits challenging the rule, and in a March 2010 settlement, the OSM agreed to rewrite the SBZ rule. In January 2013, the environmental groups reopened the litigation against OSM for failure to abide by the terms of the settlement. Oral arguments were heard on January 31, 2014. OSM published a notice on December 22, 2014, to vacate the 2008 SBZ rule to comply with an order issued by the U.S. District Court for the District of Columbia. OSM reimplemented the 1983 SBZ rule.

OSM issued its final Stream Protection Rule ("SPR") in December 2016 to replace the vacated SBZ rule. The rule would have generally prohibited the approval of permits issued pursuant to SMCRA where the proposed operations would result in "material damage to the hydrologic balance outside the permit area." Pursuant to the rule, permittees would have also been required to restore any perennial or intermittent streams that a permittee mined through. Finally, the rule would have also imposed additional baseline data collection, surface/groundwater monitoring, and bonding and financial assurance requirements. However, in February 2017, both the U.S. House of Representatives and the Senate passed resolutions disapproving the SPR under the Congressional Review Act ("CRA"). President Trump signed the resolution on February 16, 2017, and, pursuant to the CRA, the SPR "shall have no force or effect" and OSM cannot promulgate a substantially similar rule absent future legislation. Whether Congress will enact future legislation to require a new SPR rule remains uncertain.

Following the spill of coal combustion residues (“CCRs”) in the Tennessee Valley Authority impoundment in Kingston, Tennessee, in December 2009, the EPA issued proposed rules on CCRs in 2010. This final rule was published on December 19, 2014. The EPA’s final rule does not address the placement of CCRs in minefills or non-minefill uses of CCRs at coal mine sites, but, to date, no further action has been taken. These actions by OSM potentially could result in additional delays and costs associated with obtaining permits, prohibitions or restrictions relating to mining activities, and additional enforcement actions.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors to secure new surety bonds without posting collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. It is possible that surety bond issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow.

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining operations. The CAA directly impacts our coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, achieve certain emissions standards, or implement certain work practices on sources that emit various air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other coal-burning facilities. There have been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any additional measures required under applicable state and federal laws and regulations related to air emissions will make it costlier to operate coal-fired power plants and possibly other facilities that consume coal and, depending on the requirements of individual state implementation plans ("SIPs"), could make coal a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in coal's share of power generating capacity could have a material adverse effect on our business, financial condition and results of operations. Since 2010, utilities have formally announced the retirement or conversion of over 500 coal-fired electric generating units through 2030.

In addition to the greenhouse gas ("GHG") issues discussed below, the air emissions programs that may affect our operations, directly or indirectly, include, but are not limited to, the following:

- The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower-sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels. These requirements would not be supplanted by a replacement rule for the Clean Air Interstate Rule ("CAIR"), discussed below.

- The CAIR calls for power plants in 28 states and Washington, D.C. to reduce emission levels of sulfur dioxide and nitrogen oxide pursuant to a cap-and-trade program similar to the system in effect for acid rain. In June 2011, the EPA finalized the Cross-State Air Pollution Rule (“CSAPR”), a replacement rule for CAIR, which would have required 28 states in the Midwest and eastern seaboard to reduce power plant emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Under CSAPR, the first phase of the nitrogen oxide and sulfur dioxide emissions reductions would have commenced in 2012 with further reductions effective in 2014. However, in August 2012, the D.C. Circuit Court of Appeals vacated CSAPR, finding the EPA exceeded its statutory authority under the CAA and striking down the EPA’s decision to require federal implementation plans (“FIPs”), rather than SIPs, to implement mandated reductions. In its ruling, the D.C. Circuit Court of Appeals ordered the EPA to continue administering CAIR but proceed expeditiously to promulgate a replacement rule for CAIR. The U.S. Supreme Court granted the EPA’s certiorari petition appealing the D.C. Circuit Court of Appeals’ decision and heard oral arguments on December 10, 2013. In April 2014, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals’ decision, concluding that the EPA’s approach is lawful. CSAPR has been reinstated and the EPA began implementation of Phase 1 requirements in January 2015. In September 2016, EPA finalized the CSAPR Update to respond to the remand by the D.C. Circuit Court of Appeals. Implementation of Phase 2 will begin in 2017. Further litigation is expected against the CSAPR Update in the D.C. Circuit Court of Appeals. The impacts of CSAPR Update are unknown at the present time due to the implementation of Mercury and Air Toxic Standards ("MATS"), discussed below, and the significant number of coal retirements that have resulted and that potentially will result from MATS.

- In February 2012, the EPA adopted the MATS, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. In March 2013, the EPA finalized a reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits to levels attainable by existing control technologies. Appeals were filed, and oral arguments were heard by the D.C. Circuit Court of Appeals in December 2013. On April 15, 2014, the D.C. Circuit Court of Appeals upheld MATS. On June 29, 2015, the Supreme Court remanded the final rule back to the D.C. Circuit holding that the agency must consider cost before deciding whether regulation is necessary and appropriate. On December 1, 2015, the EPA issued, for comment, the proposed Supplemental Finding. In April 2016, the EPA issued a final supplemental finding upholding the rule and concluding that a cost analysis supports the MATS rule. Many electric generators have already announced retirements due to the MATS rule. Although various issues surrounding the MATS rule remain subject to litigation in the D.C. Circuit, the MATS will force generators to make capital investments to retrofit power plants and could lead to additional premature retirements of older coal-fired generating units. The announced and possible additional retirements are likely to reduce the demand for coal. 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, or Congress may decrease the future demand for coal. We continue to evaluate the possible scenarios associated with CSAPR and MATS and the effects they may have on our business and our results of operations, financial condition or cash flows.

- In January 2013, the EPA issued final Maximum Achievable Control Technology (“MACT”) standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters (“Boiler MACT”), which require owners of industrial, commercial, and institutional boilers to comply with standards for air pollutants, including mercury and other metals, fine particulates, and acid gases such as hydrogen chloride. Businesses and environmental groups have filed legal challenges to Boiler MACT in the D.C. Circuit Court of Appeals and petitioned the EPA to reconsider the rule. On December 1, 2014, the EPA announced reconsideration of the standard and will accept public comment on five issues for its standards on area sources, will review three issues related to its major-source boiler standards, and four issues relating to commercial and solid waste incinerator units. Before reconsideration, the EPA estimated the rule will affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. While some owners would make capital expenditures to retrofit boilers and process heaters, a number of boilers and process heaters could be prematurely retired. Retirements are likely to reduce the demand for coal. In August 2016, the D.C. Circuit Court of Appeals vacated a portion of the rule while remanding portions back to the EPA. In December 2016, the D.C. Circuit Court of Appeals agreed to the EPA request to remand the rule back to the EPA without vacatur. The impact of the regulations will depend on the EPA's reconsideration and the outcome of subsequent legal challenges. The impact of the regulations will depend on the EPA’s reconsideration and the outcome of subsequent legal challenges.

The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards ("NAAQS") should be revised. Pursuant to this process, the EPA has adopted more stringent NAAQS for fine particulate matter ("PM"), ozone, nitrogen oxide and sulfur dioxide. As a result, some states will be required to amend their existing SIPs to attain and maintain compliance with the new air quality standards and other states will be required to develop new SIPs for areas that were previously in "attainment" but do not attain the new standards. In addition, under the revised ozone NAAQS, significant additional emissions control expenditures may be required at coal-fired power plants. Initial non-attainment determinations related to the revised sulfur dioxide standard became effective in October 2013. In addition, in January 2013, the EPA updated the NAAQS for fine particulate matter emitted by a wide variety of sources including power plants, industrial facilities, and gasoline and diesel engines, tightening the annual PM 2.5 standard to 12 micrograms per cubic meter. The revised standard became effective in March 2013. In November 2013, the EPA proposed a rule to clarify PM 2.5 implementation requirements to the states for current 1997 and 2006 non-attainment areas. In July 2016, EPA issued a final rule for states to use in creating their plans to address particulate matter. On October 26, 2015, the EPA published a final rule that reduced the ozone NAAQS from 75 to 70 ppb. Murray Energy filed a challenge to the final rule in the D.C. Circuit. Since that time, other industry and state petitioners have filed challenges as have several environmental groups. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. In July 2009, the D.C. Circuit Court of Appeals vacated part of a rule implementing the ozone NAAQS and remanded certain other aspects of the rule to the EPA for further consideration. In June 2013, the EPA proposed a rule for implementing the 2008 ozone NAAQS. Under a consent decree published in the Federal Register in January 2017, EPA has agreed to review the NAAQS for nitrogen oxides with a final decision due by 2018 and review the NAAQS for sulfur oxide with a final decision due by 2019. New standards may impose additional emissions control requirements on new and expanded coal-fired power plants and industrial boilers. Because coal mining operations and coal-fired electric generating facilities emit particulate matter and sulfur dioxide, our mining operations and our customers could be affected when the new standards are implemented by the applicable states, and developments might indirectly reduce the demand for coal.

The EPA's regional haze program is designed to protect and improve visibility at and around national parks, national wilderness areas and international parks. Under the program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in sulfur dioxide and nitrogen oxide emissions from coal-fueled electric plants. In recent cases, the EPA has decided to negate the SIPs and impose stringent requirements through FIPs. The regional haze program, including particularly the EPA's FIPs, and any future regulations may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

The EPA's new source review ("NSR") program under the CAA in certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the NSR program. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for coal could be affected.

Carbon Dioxide Emissions

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide, which is considered a GHG. Combustion of fuel for mining equipment used in coal production also emits GHGs. Future regulation of GHG emissions in the U.S. could occur pursuant to future U.S. treaty commitments, new domestic legislation or regulation by the EPA. Congress has considered various proposals to reduce GHG emissions, and it is possible federal legislation could be adopted in the future. Internationally, the Kyoto Protocol set binding emission targets for developed countries that ratified it (the U.S. did not ratify, and Canada officially withdrew from its Kyoto commitment in 2012) to reduce their global GHG emissions. The Kyoto Protocol was nominally extended past its expiration date of December 2012, with a requirement for a new legal construct to be put into place by 2015. 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. These commitments could further reduce demand and prices for our coal. The U.S. is currently a party to the Paris Agreement; however, President Trump has said that he would "cancel the Paris Climate Agreement and stop all payments of U.S. tax dollars to U.N. global warming programs." Future participation in the Paris Agreement by the U.S. remains uncertain. However, many states, regions and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal-fired electric generating facilities. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal could be negatively impacted, which would have an adverse effect on our operations.

Even in the absence of new federal legislation, the EPA has begun to regulate GHG emissions under the CAA based on the U.S. Supreme Court's 2007 decision in *Massachusetts v. Environmental Protection Agency* that the EPA has authority to regulate GHG emissions. In 2009, the EPA issued a final rule, known as the ("Endangerment Finding")," declaring that GHG emissions, including carbon dioxide and methane, endanger public health and welfare and that six GHGs, including carbon dioxide and methane, emitted by motor vehicles endanger both the public health and welfare.

In May 2010, the EPA issued its final "tailoring rule" for GHG emissions, a policy aimed at shielding small emission sources from CAA permitting requirements. The EPA's rule phases in various GHG-related permitting requirements beginning in January 2011. Beginning July 1, 2011, the EPA requires facilities that must already obtain NSR permits (new or modified stationary sources) for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. These permits require that the permittee adopt the Best Available Control Technology ("BACT"). In June 2012, the D.C. Circuit Court of Appeals upheld these permitting regulations. In June 2014, the U.S. Supreme Court invalidated the EPA's position that power plants and other sources can be subject to permitting requirements based on their GHG emissions alone. For CO2 BACT to apply, CAA permitting must be triggered by another regulated pollutant (e.g., SO2).

As a result of revisions to its preconstruction permitting rules that became fully effective in 2011, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominantly 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. The EPA has also issued final rules requiring the monitoring and reporting of greenhouse gas emissions from certain sources.

In March 2012, the EPA proposed New Source Performance Standards ("NSPS") for carbon dioxide emissions from new fossil fuel-fired power plants. The proposal requires new coal units to meet a carbon dioxide emissions standard of 1,000 lbs. CO2/MWh, which is equivalent to the carbon dioxide emitted by a natural gas combined cycle unit. In January 2014, the EPA formally published its re-proposed NSPS for carbon dioxide emissions from new power plants. The re-proposed rule requires an emissions standard of 1,100 lbs. CO2/MWh for new coal-fired power plants. To meet such a standard, new coal plants would be required to install carbon capture and storage ("CCS") technology.

In June 2014, the EPA proposed CO2 emission "guidelines" for modified and existing fossil fuel-fired power plants under Section 111(d) of the CAA. The EPA finalized the "Clean Power Plan" ("CPP") in August 2015, which established carbon pollution standards for power plants, called CO2 emission performance rates. The EPA expects each state to develop implementation plans for power plants in its state to meet the individual state targets established in the CPP. The EPA has given states the option to develop compliance plans for annual rate-based reductions (pounds per megawatt hour) or mass-based tonnage limits for CO2. The state plans were due in September 2016, subject to potential extensions of up to two years for final plan submission. The compliance period begins in 2022, and emission reductions will be phased in up to 2030. The EPA also proposed a federal compliance plan to implement the CPP in the event that an approvable state plan is not submitted to the EPA. Although each state can determine its own method of compliance, the requirements rely on decreased use of coal and increased use of natural gas and renewables for electricity generation, as well as reductions in the amount of electricity used by consumers. Judicial challenges have been filed and oral arguments were heard by the D.C. Circuit Court of Appeals in September 2016, but a final decision has not yet been issued. On February 9, 2016, the U.S. Supreme Court issued a stay, halting implementation of the regulations. The stay will be in place until the D.C. Circuit Court of Appeals rules on the merits of the legal challenges and, if following a ruling by the D.C. Circuit Court of Appeals, a writ of certiorari from the Supreme Court is sought and granted, the stay will remain in place until the Supreme Court issues its decision on the merits. If, despite the legal challenges, the rules were implemented in their current form, demand for coal will likely be further decreased, potentially significantly, and adversely impact our business. Future implementation of the CPP remains uncertain.

In August 2015, the EPA released final rules requiring newly constructed coal-fired steam electric generating units ("EGUs") to emit no more than 1,400 lbs CO_2/MWh (gross) and be constructed with CCS to capture 16% of CO_2 produced by an electric generating unit burning bituminous coal. At the same time, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources required reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates (lbs per megawatt hour) for each state and has an overall goal to achieve a 32% reduction of carbon dioxide emissions from 2005 levels by 2030. The compliance period begins in 2022 and in 2030 CO_2 emissions goals must be met. Challenges to the NSPS have been filed in U.S. Court of Appeal for the D.C. Circuit and oral arguments are set for April 2017.

Collectively, these requirements have led to premature retirements and could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has rejected legislation to restrict carbon dioxide emissions from existing power plants and it is unclear whether the EPA has the legal authority to regulate carbon dioxide emissions for existing and modified power plants as proposed in the NSPS and CPP. Substantial limitations on GHG emissions could adversely affect demand for the coal we produce.

There have been numerous protests of and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to GHG emissions. For instance, various state regulatory authorities have rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fueled power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board. In addition, over thirty states have currently adopted "renewable energy standards" or "renewable portfolio standards," which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Other states may adopt similar requirements, and federal legislation is a possibility in this area. To the extent these requirements affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal. Finally, a federal appeals court allowed a lawsuit pursuing federal common law claims to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of carbon dioxide, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court overturned that decision in June 2011, holding that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions. The Supreme Court did not, however, decide whether similar claims can be brought under state common law. As a result, despite this favorable ruling, tort-type liabilities remain a concern.

In addition, environmental advocacy groups have filed a variety of judicial challenges claiming that the environmental analyses conducted by federal agencies before granting permits and other approvals necessary for certain coal activities do not satisfy the requirements of the National Environmental Policy Act ("NEPA"). These groups assert that the environmental analyses in question do not adequately consider the climate change impacts of these particular projects. In December 2014, the Council on Environmental Quality ("CEQ") released updated draft guidance discussing how federal agencies should consider the effects of GHG emissions and climate change in their NEPA evaluations. The guidance encourages agencies to provide more detailed discussion of the direct, indirect, and cumulative impacts of a proposed action's reasonably foreseeable emissions and effects. This guidance could create additional delays and costs in the NEPA review process or in our operations, or even an inability to obtain necessary federal approvals for our future operations, including due to the increased risk of legal challenges from environmental groups seeking additional analysis of climate impacts.

Many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten Northeastern states entered into the Regional Greenhouse Gas Initiative agreement ("RGGI"), calling for implementation of a cap and trade program aimed at reducing carbon dioxide emissions from power plants in the participating states. The members of RGGI have established in statutes and/or regulations a carbon dioxide trading program. Auctions for carbon dioxide allowances under the program began in September 2008. Though New Jersey withdrew from RGGI in 2011, since its inception, several additional northeastern states and Canadian provinces have joined as participants or observers.

Following the RGGI model, five Western states launched the Western Regional Climate Action Initiative to identify, evaluate, and implement collective and cooperative methods of reducing GHG in the region to 15% below 2005 levels by 2020. These states were joined by two additional states and four Canadian provinces and became collectively known as the Western Climate Initiative Partners. However, in November 2011, six states withdrew, leaving California and the four Canadian provinces as members. At a January 2012 stakeholder meeting, this group confirmed a commitment and timetable to create the largest carbon market in North America and provide a model to guide future efforts to establish national approaches in both Canada and the U.S. to reduce GHG emissions. It is likely that these regional efforts will continue.

It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with coal production and consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, which could have a material adverse effect on our business, financial condition and results of operations.

Water Discharge

The Federal Clean Water Act ("CWA") and similar state and local laws and regulations affect coal mining operations by imposing restrictions on effluent discharge into waters and the discharge of dredged or fill material into the waters of the U.S. Regular monitoring, as well as compliance with reporting requirements and performance standards, is a precondition for the issuance and renewal of permits governing the discharge of pollutants into water. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future "fill" permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

The U.S. Army Corps of Engineers ("Corps of Engineers") maintains two permitting programs under CWA Section 404 for the discharge of dredged or fill material: one for "individual" permits and a more streamlined program for "general" permits. In June 2010, the Corps of Engineers suspended the use of "general" permits under Nationwide Permit 21 ("NWP 21") in the Appalachian states. In February 2012, the Corps of Engineers reissued the final 2012 NWP 21. The Center for Biological Diversity later filed a notice of intent to sue the Corps of Engineers based on allegations the 2012 NWP 21 program violated the Endangered Species Act ("ESA"). The Corps of Engineers and National Marine Fisheries Service ("NMFS") have completed their programmatic ESA Section 7 consultation process on the Corps of Engineers' 2012 NWP 21 package, and NMFS has issued a revised biological opinion finding that the NWP 21 program does not jeopardize the continued existence of threatened and endangered species and will not result in the destruction or adverse modification of designated critical habitat. However, the opinion contains 12 additional protective measures the Corps of Engineers will implement in certain districts to "enhance the protection of listed species and critical habitat." While these measures will not affect previously verified permit activities where construction has not yet been completed, several Corps of Engineers districts with mining operations will be impacted by the additional protective measures going forward. These measures include additional reporting and notification requirements, potential imposition of new regional conditions and additional actions concerning cumulative effects analyses and mitigation. Our coal mining operations typically require Section 404 permits to authorize activities such as the creation of slurry ponds and stream impoundments. The CWA authorizes the EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, the EPA began reviewing Section 404 permits issued by the Corps of Engineers for coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

For instance, even though the State of West Virginia has been delegated the authority to issue permits for coal mines in that state, the EPA is taking a more active role in its review of National Pollutant Discharge Elimination System ("NPDES") permit applications for coal mining operations in Appalachia. The EPA has stated that it plans to review all applications for NPDES permits. Indeed, final guidance issued by the EPA in July 2011, encouraged the EPA Regions 3, 4 and 5 to object to the issuance of state program NPDES permits where the Region does not believe that the proposed permit satisfies the requirements of the CWA, and with regard to state issued general Section 404 permits, support the previously drafted Enhanced Coordination Procedures ("ECP"). In October 2011, the U.S. District Court for the District of Columbia rejected the ECP on several different legal grounds and later, this same court enjoined the EPA from any further usage of its final guidance. The U.S. Supreme Court denied a request to review this decision. Any future application of procedures similar to ECP, such as may be enacted following notice and comment rulemaking, would have the potential to delay issuance of permits for surface coal mines, or to change the conditions or restrictions imposed in those permits.

The EPA also has statutory "veto" power over a Section 404 permit if the EPA determines, after notice and an opportunity for a public hearing, that the permit will have an "unacceptable adverse effect." In January 2011, the EPA exercised its veto power to withdraw or restrict the use of a previously issued permit for Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action was the first time that such power was exercised with regard to a previously permitted coal mining project. A challenge to the EPA's exercise of this authority was made in the U.S. District Court for the District of Columbia and in March 2012, that court ruled that the EPA lacked the statutory authority to invalidate an already issued Section 404 permit retroactively. In April 2013, the D.C. Circuit Court of Appeals reversed this decision and authorized the EPA to retroactively veto portions of a Section 404 permit. The U.S. Supreme Court denied a request to review this decision. Any future use of the EPA's Section 404 "veto" power could create uncertainly with regard to our continued use of current permits, as well as impose additional time and cost burdens on future operations, potentially adversely affecting our coal revenue. In addition, the EPA initiated a preemptive veto prior to the filing of any actual permit application for a copper and gold mine based on fictitious mine scenario. The implications of this decision could allow the EPA to bypass the state permitting process and engage in watershed and land use planning.

Total Maximum Daily Load ("TMDL") regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired water body can receive and still meet state water quality standards, and to allocate pollutant loads among the point and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an antidegradation review before approving discharge permits. The adoption of new TMDL-related allocations or any changes to antidegradation policies for streams near our coal mines could require more costly water treatment and could adversely affect our coal production.

In June 2015, the EPA issued a new rule providing a definition of the WOTUS. This rule is broadly written and expands the EPA and Corps of Engineers jurisdiction. WOTUS creates new federal authority over lands, ditches, and potentially on-site mining waters. Of critical concern to our industry is the possibility that many water features commonly found on mine sites which are currently not considered jurisdictional could nevertheless fall within the definition of WOTUS under the proposed rule. Ditches, closed loop systems, on-site ponds, impoundments, and other water management features are integral to mining operations, and are used to manage on-site waters in an environmentally sound and frequently statutorily mandated manner. The rule could lead to substantially increased permitting requirements with more costs, delays, and increased risk of litigation. Industry Groups have challenged the final rule. Multiple suits were filed across the country by states, industry, and outside parties. The Coal Industry is currently active in suits in the Texas District Court and 6th Circuit Court of Appeals, though the coalition has moved to intervene in several suits (to both defend certain provisions in the rule important to industry and contest overly-broad provisions). The 6th Circuit ordered a nationwide stay of the rule that will remain in effect at least until it issues its jurisdictional determination (expected in the near future). At present, it is not clear whether an appellate court or multiple district courts will exercise jurisdiction over the claims. In January 2016, the U.S. Supreme Court agreed to resolve the jurisdictional questions and decide the proper court or courts to hear the challenges to the WOTUS rule.

Hazardous Substances and Wastes

The Federal Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), otherwise known as the “Superfund” law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liabilities under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

The Federal Resource Conservation and Recovery Act (“RCRA”) and corresponding state laws regulating hazardous waste affect coal mining operations by imposing requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on our operations.

In June 2010, the EPA released a proposed rule to regulate the disposal of certain coal combustion by-products (“CCB”). The proposed rule set forth two very different options for regulating CCB under RCRA. The first option called for regulation of CCB as a hazardous waste under Subtitle C, which creates a comprehensive program of federally enforceable requirements for waste management and disposal. The second option utilized Subtitle D, which would give the EPA authority to set performance standards for waste management facilities and would be enforced primarily through citizen suits. The proposal leaves intact the Bevill exemption for beneficial uses of CCB. In April 2012, several environmental organizations filed suit against the EPA to compel the EPA to take action on the proposed rule. Several companies and industry groups intervened. A consent decree was entered on January 29, 2014.

The EPA finalized the CCB rule on December 19, 2014, setting nationwide solid nonhazardous waste standards for CCB disposal. On April 17, 2015, the EPA finalized regulations under the solid waste provisions (“Subtitle D”) of RCRA and not the hazardous waste provisions (“Subtitle C”) which became effective on October 19, 2015. EPA affirms in the preamble to the final rule that “this rule does not apply to CCR placed in active or abandoned underground or surface mines.” Instead, “the U.S. Department of Interior (“DOI”) and EPA will address the management of CCR in mine fills in a separate regulatory action(s).” While classification of CCB as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers’ operating costs and potentially reduce their ability to purchase coal.

On November 3, 2015, EPA published the final rule Effluent Limitations Guidelines and Standards (“ELG”), revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. The combined effect of the CCR and ELG regulations has forced power generating companies to close existing ash ponds and will likely force the closure of certain older existing coal burning power plants that cannot comply with the new standards. These regulations add costs to the operation of coal burning power plants on top of other regulations like the 2014 regulations issued under Section 316(b) of the CWA that affects the cooling water intake structures at power plants in order to reduce fish impingement and entrainment. Individually and collectively, these regulations could, in turn, impact the market for our products.

Endangered Species Act

The federal Endangered Species Act ("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. If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered, we could be subject to additional regulatory and permitting requirements.

Other Environmental, Health and Safety Regulations

In addition to the laws and regulations described above, we are subject to regulations regarding underground and above ground storage tanks in which we may store petroleum or other substances. Some monitoring equipment that we use is subject to licensing under the Federal Atomic Energy Act. Water supply wells located on our properties are subject to federal, state, and local regulation. In addition, our use of explosives is subject to the Federal Safe Explosives Act. We are also required to comply with the Federal Safe Drinking Water Act, the Toxic Substance Control Act, and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these regulations should not have a material adverse effect on our business, financial condition or results of operations.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, steel-related (including roof control) products, belting products, lubricants, electricity, fuel and tires. Although we have many long, well-established relationships with our key suppliers, we do not believe that we are dependent on any of our individual suppliers other than for purchases of electricity. The supplier base providing mining materials has been relatively consistent in recent years. Purchases of certain underground mining equipment are concentrated with one principle supplier; however, supplier competition continues to develop.

Illinois Basin (ILB)

The coal industry underwent a significant transformation in the early 1990s, as greater environmental accountability was established in the electric utility industry. Through the U.S. Clean Air Act, acceptable baseline levels were established for the release of sulfur dioxide in power plant emissions. In order to comply with the new law, most utilities switched fuel consumption to low-sulfur coal, thereby stripping the ILB of over 50 million tons of annual coal demand. This strategy continued until mid-2000 when a shortage of low-sulfur coal drove up prices. This price increase combined with the assurance from the U.S. government that the utility industry would be able to recoup their costs to install scrubbers caused utilities to begin investing in scrubbers on a large scale. With scrubbers, the ILB has reopened as a significant fuel source for utilities and has enabled them to burn lower cost, high sulfur coal.

The ILB consists of coal mining operations covering more than 50,000 square miles in Illinois, Indiana and western Kentucky. The ILB is centrally located between four of the largest regions that consume coal as fuel for electricity generation (East North Central, West South Central, West North Central and East South Central). The region also has access to sufficient rail and water transportation routes that service coal-fired power plants in these regions as well as other significant coal consuming regions of the South Atlantic and Middle Atlantic.

U. S. Coal Industry

The major coal production basins in the U.S. include Central Appalachia (CAPP), Northern Appalachia (NAPP), Illinois Basin (ILB), Powder River Basin (PRB) and the Western Bituminous region (WB). CAPP includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. NAPP includes Maryland, Ohio, Pennsylvania and northern West Virginia. The ILB includes Illinois, Indiana and western Kentucky. The PRB is located in northeastern Wyoming and southeastern Montana. The WB includes western Colorado, eastern Utah and southern Wyoming.

Coal type varies by basin. Heat value and sulfur content are important quality characteristics and determine the end use for each coal type.

Coal in the U.S. is mined through surface and underground mining methods. The primary underground mining techniques are longwall mining and continuous (room-and-pillar) mining. The geological conditions dictate which technique to use. Our mines use the continuous technique. In continuous mining, rooms are cut into the coal bed leaving a series of pillars, or columns of coal, to help support the mine roof and control the flow of air. Continuous mining equipment cuts the coal from the mining face. Generally, openings are driven 20' wide and the pillars are rectangular in shape measuring 40'x 40'. As mining advances, a grid-like pattern of entries and pillars is formed. Roof bolts are used to secure the roof of the mine. Battery cars move the coal to the conveyor belt for transport to the surface. The pillars can constitute up to 50% of the total coal in a seam.

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. We compete against large producers such as Peabody Energy Corporation (NYSE: BTUUQ) and Alliance (NASDAQ: ARLP) and small producers.

Employees

We have 748 employees.

Other

We have no significant patents, trademarks, licenses, franchises or concessions.

Our Denver office is located at 1660 Lincoln Street, Suite 2700, Denver, Colorado 80264, phone 303.839.5504 and Sunrise Coal's corporate office is located at 1183 East Canvasback Drive, Terre Haute, Indiana 47802, phone 812.299.2800. Terre Haute is approximately 70 miles west of Indianapolis. Our website is www.halladorenergy.com and Sunrise Coal's is www.sunrisecoal.com.

ITEM 1A. RISK FACTORS.

Risks Related to our Business

Global economic conditions or economic conditions in any of the industries in which our customers operate as well as sustained uncertainty in financial markets may have material adverse impacts on our business and financial condition that we currently cannot predict.

Weakness in global economic conditions or economic conditions in any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for electricity in the U.S. may decline if economic conditions deteriorate, which may negatively impact the revenue, margins and profitability of our business;
- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and
- our future ability to access the capital markets may be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including development of our coal reserves.

A substantial or extended decline in coal prices could negatively impact our results of operations.

Our results of operations are primarily dependent upon the prices we receive for our coal, as well as our ability to improve productivity and control costs. The prices we receive for our production depends upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions and patterns;
- the proximity to and capacity of transportation facilities;
- competition from other coal suppliers;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption, including the impact of technological advances on energy consumption; and
- prevailing economic conditions.

Any adverse change in these factors could result in weaker demand and lower prices for our products. A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenue to the extent we are not protected by the terms of existing coal supply agreements.

Competition within the coal industry may adversely affect our ability to sell coal, and excess production capacity in the industry could put downward pressure on coal prices.

We compete with other coal producers for domestic coal sales. The most important factors on which we compete are delivered price (*i.e.*, the cost of coal delivered to the customer, including transportation costs, which are generally paid by our customers either directly or indirectly), coal quality characteristics, contract flexibility (*e.g.*, volume optionality and multiple supply sources) and reliability of supply. Some competitors may have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers may impact our ability to retain or attract customers and could adversely impact our revenue and cash from operations. In addition, declining prices from an oversupply of coal in the market could reduce our revenue and cash from operations.

Changes in consumption patterns by utilities regarding the use of coal have affected our ability to sell the coal we produce. Since 2000, coal's share of U.S. electricity production has fallen from 53% to 30%, while natural gas' share has increased from 16% to 34%.

The domestic electric utility industry accounts for over 92% of domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas and fuel oil as well as alternative sources of energy. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed in the U.S. to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain.

In addition, future environmental regulation of GHG emissions could accelerate the use by utilities of fuels other than coal. In addition, state and federal mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. For example, the EPA's CPP will likely incentivize additional electric generation from natural gas and renewable sources, and Congress has extended tax credits for renewables. In addition, a number of states have enacted mandates that require electricity suppliers to rely on renewable energy sources in generating a certain percentage of power. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. A decrease in coal consumption by the domestic electric utility industry could adversely affect the price of coal, which could negatively impact our results of operations and reduce our cash from operations.

Extensive environmental laws and regulations affect coal consumers, and have corresponding effects on the demand for coal as a fuel source.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from coal-fired electric power plants, which are the ultimate consumers of much of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. These laws and regulations may affect demand and prices for coal. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. Further, far-reaching federal regulations promulgated by the EPA in the last five years, such as CSAPR and MATS, have led to the premature retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the U.S. At former President Obama's direction, the EPA proposed CO2 emissions requirements, known as the CPP, for existing and modified power plants and published such rules on October 23, 2015. As a result of these current and proposed laws, regulations and regulatory initiatives, electricity generators may elect to switch to other fuels that generate less of these emissions or by-products, further reducing demand for coal. Please read "Item 1. Business—Regulation and Laws—"*Air Emission,"* "*—Carbon Dioxide Emissions*" and "*—Hazardous Substances and Wastes*

Increased regulation of GHG emissions could result in increased operating costs and reduced demand for coal as a fuel source, which could reduce demand for our products, decrease our revenue and reduce our profitability.

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. On December 15, 2009, the EPA published the Endangerment Finding asserting that emissions of carbon dioxide and other GHGs present an endangerment to public health and the environment, and the EPA has begun to regulate GHG emissions pursuant to the CAA. The EPA has finalized a rule to regulate GHG emissions from new power plants. The finalized standard requires CCS, a technology that is not yet commercially feasible without government subsidies and that has not been demonstrated in the marketplace. This requirement effectively prevents construction of new coal fired power plants. In August 2015, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources requires reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates (lbs per megawatt hour) for each state and has an overall goal to achieve a 32% reduction of carbon dioxide emissions from 2005 levels by 2030. If upheld by courts, the regulation could lead to premature retirements of coal-fired electric generating units and significantly reduce the demand for coal. In addition, many states and regions have adopted GHG initiatives. Also, there have been numerous protests of, and challenges to, the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to GHG emissions. Please read "Item 1. Business—Regulation and Laws—*Air Emissions*" and "*—Carbon Dioxide Emissions*."

Numerous political and regulatory authorities and governmental bodies, as well as environmental activist groups, are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, domestically and internationally, thereby further reducing the demand and pricing for coal and potentially materially and adversely impacting our future financial results, liquidity and growth prospects.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate issues, are resulting in increased regulation of coal combustion in many jurisdictions, unfavorable lending policies by lending institutions and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities. Global climate issues continue to attract public and scientific attention. Some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Numerous reports, such as the Fourth and Fifth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants.

Federal, state and local governments may pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may decrease demand for our coal products. The CPP is one of a number of recent developments aimed at limiting GHG emissions which could limit the market for some of our products by encouraging electric generation from sources that do not generate the same amount of GHG emissions. Enactment of laws or passage of regulations regarding emissions from the combustion of coal by the U.S., states, or other countries, could also result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. For example, the agreement resulting from the 2015 United Nations Framework Convention on Climate Change contains voluntary commitments by numerous countries to reduce their GHG emissions, and could result in additional firm commitments by various nations with respect to future GHG emissions. These commitments could further disfavor coal-fired generation, particularly in the medium to long-term.

Congress has extended certain tax credits for renewable sources of electric generation, which will increase the ability of these sources to compete with our coal products in the market. In addition, the U.S. Department of Interior recently announced a moratorium on issuing certain new coal leases on federal land while the Bureau of Land Management undertakes a programmatic review of the federal coal program. While none of our operations are located on federal lands impacted by this moratorium, it does signal increased attention at the federal level to coal mining practices and the GHG emissions resulting from coal combustion.

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was signed into law in October 2015 that requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, several major banks enacted such policies. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

In addition, several well-funded non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. Collectively, these actions and campaigns could adversely impact our future financial results, liquidity and growth prospects.

Government regulations have resulted and could continue to result in significant retirements of coal-fired electric generating units. Retirements of coal-fired electric generating units decrease the overall capacity to burn coal and negatively impact coal demand.

Since 2010, utilities have formally announced the retirement or conversion of 558 coal-fired electric generating units through 2030. These retirements and conversions amount to over 93,000 megawatts ("MW") or approximately 30% of the 2010 total coal electric generating capacity. At the end of 2016 retirement and conversions affecting 60,000 MW, or approximately 19% of the 2010 total coal electric generating capacity, are estimated to have occurred. Most of these announced and completed retirements and conversions have been attributed to the EPA regulations, although other factors such as an aging coal fleet and low natural gas prices have also played a role. The reduction in coal electric capacity negatively impacts overall coal demand. Additional regulations and other factors could lead to additional retirements and conversions and, thereby, additional reductions in the demand for coal.

***Plaintiffs in federal court litigation have attempted to pursue tort claims based on the alleged effects of climate change*.**

In 2004, eight states and New York City sued five electric utility companies in *Connecticut v. American Electric Power Co.* Invoking the federal and state common law of public nuisance, plaintiffs sought an injunction requiring defendants to abate their contribution to the nuisance of climate change by capping carbon dioxide emissions and then reducing them. In June 2011, the U.S. Supreme Court issued a unanimous decision holding that the plaintiffs' federal common law claims were displaced by federal legislation and regulations. The U.S. Supreme Court did not address the plaintiffs' state law tort claims and remanded the issue of preemption for the district court to consider. While the U.S. Supreme Court held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, tort-type liabilities remain a possibility and a source of concern. Proliferation of successful climate change litigation could adversely impact demand for coal and ultimately have a material adverse effect on our business, financial condition and results of operations.

The stability and profitability of our operations could be adversely affected if our customers do not honor existing contracts or do not extend existing or enter into new long-term contracts for coal.

In 2016, substantially all of our sales were under contracts having a term greater than one year, which we refer to as long-term contracts. Long-term sales contracts have historically provided a relatively secure market for the amount of production committed under the terms of the contracts. From time to time industry conditions may make it more difficult for us to enter into long-term contracts with our electric utility customers, and if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire, which could subject a portion of our revenue stream to the increased volatility of the spot market.

Some of our long-term coal sales contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.

Some of our long-term contracts contain provisions that allow for the purchase price to be renegotiated at periodic intervals. Any adjustment or renegotiation leading to a significantly lower contract price could adversely affect our operating profit margins. Accordingly, long-term contracts may provide only limited protection during adverse market conditions. In some circumstances, failure of the parties to agree on a price under a reopener provision can also lead to early termination of a contract.

Several of our long-term contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain events that are beyond the customer’s reasonable control. Such events may include labor disputes, mechanical malfunctions and changes in government regulations, including changes in environmental regulations rendering use of our coal inconsistent with the customer’s environmental compliance strategies. Additionally, most of our long-term contracts contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments or termination of the contracts. In the event of early termination of any of our long-term contracts, if we are unable to enter into new contracts on similar terms, our business, financial condition and results of operations could be adversely affected.

We depend on a few customers for a significant portion of our revenue, and the loss of one or more significant customers could affect our ability to maintain the sales volume and price of the coal we produce.

During 2016, we derived 90% of our revenue from five customers and at least 10% of our revenue from each of them. If we were to lose any of these customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition and results of operations.

Litigation resulting from disputes with our customers may result in substantial costs, liabilities and loss of revenue.

From time to time we have disputes with our customers over the provisions of long-term coal supply contracts relating to, among other things, coal pricing, quality, quantity and the existence of specified conditions beyond our or our customers' control that suspend performance obligations under the particular contract. Disputes may occur in the future and we may not be able to resolve those disputes in a satisfactory manner, which could have a material adverse effect on our business, financial condition and results of operations.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If the creditworthiness of our customers declines significantly, our business could be adversely affected. In addition, if a customer refuses to accept shipments of our coal for which they have an existing contractual obligation, our revenue will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

Our profitability may decline due to unanticipated mine operating conditions and other events that are not within our control and that may not be fully covered under our insurance policies.

Our mining operations are influenced by changing conditions or events that can affect production levels and costs at particular mines for varying lengths of time and, as a result, can diminish our profitability. These conditions and events include, among others:

- mining and processing equipment failures and unexpected maintenance problems;
- unavailability of required equipment;
- prices for fuel, steel, explosives and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in thickness of the layer, or seam, of coal;
- amounts of overburden, partings, rock and other natural materials;
- weather conditions, such as heavy rains, flooding, ice and other natural events affecting operations, transportation or customers;
- accidental mine water discharges and other geological conditions;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- fires;
- employee injuries or fatalities;
- labor-related interruptions;
- increased reclamation costs;
- inability to acquire, maintain or renew mining rights or permits in a timely manner, if at all;
- fluctuations in transportation costs and the availability or reliability of transportation; and
- unexpected operational interruptions due to other factors.

These conditions have the potential to significantly impact our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenue and profitability, which could materially adversely impact our quarterly or annual results.

Although none of our employees are members of unions, our work force may not remain union-free in the future.

None of our employees are represented under collective bargaining agreements. However, all of our work force may not remain union-free in the future, and legislative, regulatory or other governmental action could make it more difficult to remain union-free. If some or all of our currently union-free operations were to become unionized, it could adversely affect our productivity and increase the risk of work stoppages at our mining complexes. In addition, even if we remain union-free, our operations may still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

Our mining operations are subject to extensive and costly laws and regulations, and such current and future laws and regulations could increase current operating costs or limit our ability to produce coal.

We are subject to numerous federal, state and local laws and regulations affecting the coal mining industry, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air and water quality standards, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge or release of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Certain of these laws and regulations may impose strict liability without regard to fault or legality of the original conduct. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial liabilities, and the issuance of injunctions limiting or prohibiting the performance of operations. Complying with these laws and regulations may be costly and time consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, which could materially affect our mining operations, cash flow, and profitability, either through direct impacts on our mining operations, or indirect impacts that discourage or limit our customers' use of coal. Please read "Item 1. Business—Regulations and Laws."

State and federal laws addressing mine safety practices impose stringent reporting requirements and civil and criminal penalties for violations. Federal and state regulatory agencies continue to interpret and implement these laws and propose new regulations and standards. Implementing and complying with these laws and regulations has increased and will continue to increase our operational expense and to have an adverse effect on our results of operation and financial position. For more information, please read "Item 1. Business—Regulation and Laws—*Mine Health and Safety Laws*."

We may be unable to obtain and renew permits necessary for our operations, which could reduce our production, cash flow and profitability.

Mining companies must obtain numerous governmental permits or approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required to conduct our operations may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict our ability to economically conduct our mining operations. Limitations on our ability to conduct our mining operations due to the inability to obtain or renew necessary permits or similar approvals could reduce our production, cash flow and profitability. Please read "Item 1. Business—Regulations and Laws—*Mining Permits and Approvals*."

The EPA has begun reviewing permits required for the discharge of overburden from mining operations under Section 404 of the CWA. Various initiatives by the EPA regarding these permits have increased the time required to obtain and the costs of complying with such permits. In addition, the EPA previously exercised its "veto" power to withdraw or restrict the use of previously issued permits in connection with one of the largest surface mining operations in Appalachia. The EPA's action was ultimately upheld by a federal court. As a result of these developments, we may be unable to obtain or experience delays in securing, utilizing or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read "Item 1. Business—Regulations and Laws—*Water Discharge*."

In addition, some of our permits could be subject to challenges from the public, which could result in additional costs or delays in the permitting process, or even an inability to obtain permits, permit modifications, or permit renewals necessary for our operations.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenue by causing us to reduce our production or by impairing our ability to supply coal to our customers.

Transportation costs represent a significant portion of the total cost of coal for our customers and, as a result, the cost of transportation is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources. Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks or other events could temporarily impair our ability to supply coal to our customers. Our transportation providers may face difficulties in the future that may impair our ability to supply coal to our customers, resulting in decreased revenue. If there are disruptions of the transportation services provided by our primary rail carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. For instance, difficulty in coordinating the many eastern coal loading facilities, the large number of small shipments, the steeper average grades of the terrain and a more unionized workforce are all issues that combine to make coal shipments originating in the eastern U.S. inherently more expensive on a per-mile basis than coal shipments originating in the western U.S. Historically, high coal transportation rates from the western coal producing areas into certain eastern markets limited the use of western coal in those markets. Lower rail rates from the western coal producing areas to markets served by eastern U.S. coal producers have created major competitive challenges for eastern coal producers. In the event of further reductions in transportation costs from western coal producing areas, the increased competition with certain eastern coal markets could have a material adverse effect on our business, financial condition and results of operations.

It is possible that states in which our coal is transported by truck may modify or increase enforcement of their laws regarding weight limits or coal trucks on public roads. Such legislation and enforcement efforts could result in shipment delays and increased costs. An increase in transportation costs could have an adverse effect on our ability to increase or to maintain production and could adversely affect revenue.

We may not be able to successfully grow through future acquisitions.

We have expanded our operations by adding and developing mines and coal reserves in existing, adjacent and neighboring properties. We continually seek to expand our operations and coal reserves. Our future growth could be limited if we are unable to continue to make acquisitions, or if we are unable to successfully integrate the companies, businesses or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of undertaking these acquisitions are unknown. Moreover, any acquisition could be dilutive to earnings. Our ability to make acquisitions in the future could require significant amounts of financing that may not be available to us under acceptable terms and may be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

Expansions and acquisitions involve a number of risks, any of which could cause us not to realize the anticipated benefits.

If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion and acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental or mine safety liabilities) of, expansion and acquisition opportunities;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition;
- problems that could arise from the integration of the new operations; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or acquisition opportunity.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an expansion or acquisition. Any expansion or acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. In addition, future expansions or acquisitions could result in us assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous expansions and/or acquisitions.

Completion of growth projects and future expansion could require significant amounts of financing that may not be available to us on acceptable terms, or at all.

We plan to fund capital expenditures for our current growth projects with existing cash balances, future cash flows from operations, borrowings under credit facilities and cash provided from the issuance of debt or equity. Weakness in the energy sector in general and coal in particular has significantly impacted access to the debt and equity capital markets. Accordingly, our funding plans may be negatively impacted by this constrained environment as well as numerous other factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we may be unable to refinance our current credit facilities when they expire or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet their funding obligations. Furthermore, additional growth projects and expansion opportunities may develop in the future that could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

Various factors could adversely impact the debt and equity capital markets as well as our credit ratings or our ability to remain in compliance with the financial covenants under our then current debt agreements, which in turn could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth and future expansions as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our plans.

The unavailability of an adequate supply of coal reserves that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because we deplete our reserves as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal reserves that are economically recoverable. Replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

The estimates of our coal reserves may prove inaccurate and could result in decreased profitability.

The estimates of our coal reserves may vary substantially from actual amounts of coal we are able to economically recover. All of the reserves presented in this Annual Report on Form 10-K constitute proven and probable reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulation and taxes by governmental agencies; and
- future improvements in mining technology; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Any inaccuracy in the estimates of our reserves could result in higher than expected costs and decreased profitability.

Mining in certain areas in which we operate is more difficult and involves more regulatory constraints than mining in other areas of the U.S., which could affect the mining operations and cost structures of these areas.

The geological characteristics of some of our coal reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those characteristics of the depleting mines. In addition, permitting, licensing and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. These factors could materially adversely affect the mining operations and cost structures of, and our customers' ability to use coal produced by, our mines.

Unexpected increases in raw material costs could significantly impair our operating profitability.

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, petroleum products and other raw materials in various pieces of mining equipment, supplies and materials, including the roof bolts required by the room-and-pillar method of mining. Steel prices and the prices of scrap steel, natural gas and coking coal consumed in the production of iron and steel fluctuate significantly and may change unexpectedly. There may be acts of nature or terrorist attacks or threats that could also impact the future costs of raw materials. Future volatility in the price of steel, petroleum products or other raw materials will impact our operational expenses and could result in significant fluctuations in our profitability.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required by state and federal law to have these bonds in place before mining can commence or continue, failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third-party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our financing arrangements.

Terrorist attacks or cyber-incidents could result in information theft, data corruption, operational disruption and/or financial loss.

Like most companies, we have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our business partners, analyze mine and mining information, estimate quantities of coal reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the U.S. Deliberate attacks on, or security breaches in, our systems or infrastructure, or the systems or infrastructure of third parties, or cloud-based applications could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third-party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, results of operations and cash flows. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Risks Related to Our Indebtedness and Liquidity

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

As disclosed in Note 4 to our financial statements, there are two key ratio covenants stated in our credit agreement: (i) a minimum debt service coverage ratio of 1.25 to 1 and (ii) a maximum leverage ratio (funded debt/EBITDA) not to exceed 4.50 to 1. At December 31, 2016, our debt service coverage ratio was 2.11 and our leverage ratio was 2.95. Therefore, we were in compliance with these two ratios.

Our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

At December 31, 2016, our debt was $239 million. Our leverage may:

- adversely affect our ability to finance future operations and capital needs;
- limit our ability to pursue acquisitions and other business opportunities;
- make our results of operations more susceptible to adverse economic or operating conditions; and

Various limitations in our debt agreements may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Risk Related to Possible Future Impairment Charge

In December 2016, the deterioration of the North end of the Carlisle mine, coupled with lower coal prices led us to determine that the Northern end of the Carlisle mine no longer could be safely and profitably mined. Thus, the decision was made to seal off the North end of the mine. Sealing will be completed in the 1st quarter of 2017. We identified specific assets totaling $16.6 million ($15.1 million of property and equipment and $1.5 million of advanced royalties) that were written off in 2016. After the impairment, the Carlisle assets had an aggregate carrying value of $118 million at December 31, 2016. We conducted a review of the Carlisle mine assets and determined that no further impairment charge was necessary. If, in future periods, we reduce our estimate of the future net cash flows attributable to the Carlisle Mine, it may result in additional future impairment of such assets and such charges could be significant. None of our other assets are considered impaired.

ITEM 1B. UNRESOLVED STAFF COMMENTS. None.

ITEM 2. PROPERTIES.

See Item 7 MDA for a discussion of our mines.

Coal Reserve Estimates

“Reserves” are defined by the SEC Industry Guide 7 as that part of a mineral deposit, which could be economically and legally extracted or produced at the time of the reserve determination. “Recoverable” reserves mean coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. “Proven (measured) reserves” are defined by Guide 7 as 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. “Probable reserves” are defined by Guide 7 as reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) 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.

Our reserve estimates were prepared by Scott McGuire and Samuel Elder, two of our mining engineers. Mr. McGuire is a licensed Professional Engineer in the State of Indiana and Kentucky and has fifteen years' experience estimating coal reserves. Mr. Elder is a licensed Professional Engineer in the State of Indiana and has over twenty-seven years' experience estimating coal reserves.

Standards set forth by the USGS were used to place areas of the mine reserves into the Proven (measured) and Probable (indicated) categories. Under these standards, coal within 1,320' of a data point is considered to be proven, and coal within 1,320' to 3,960' is placed in the Probable category. Only tons greater than 4' in thickness are included in our underground reserves. All reserves are stated as a final salable product.

Prior to acquiring coal mineral leases, title abstractors conduct a preliminary title search on the property. This information provides a strong indication of the coal owner, with whom we will enter into a lease. The next step is to execute a lease with the owner, giving us the rights to explore and mine the property. Prior to mining, attorneys review the chain of mineral ownership to verify the lessor is the mineral owner. Prior to purchasing coal properties, we follow a similar process

ITEM 3. LEGAL PROCEEDINGS. None

ITEM 4. MINE SAFETY DISCLOSURES:

As a testament to our commitment to mine safety, in October 2016, our mine rescue team competed in and won the 2016 Nationwide Mine Rescue Skills Championship contest in Madisonville, Kentucky. Thirteen teams from five different states competed in the competition. The Nationwide Skills Championship is divided into seven skills competitions and a written test. Refer to www.halladorenergy.com for a link to more information regarding this prestigious award.

See Exhibit 95 to this Form 10-K for a listing of our mine safety violations.

PART II

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

Stock Price Information

Our common stock is traded on the NASDAQ Capital Market under the symbol HNRG. 46% of our stock is held by our officers, directors and their affiliates. The following table sets forth the high and low closing sales price for the periods indicated:

	Dividends Paid	High	Low
2017			
January 1 through March 8	$ .04	$9.79	$8.32
2016			
Fourth quarter	.04	10.02	7.24
Third quarter	.04	8.26	4.50
Second quarter	.04	5.10	4.03
First quarter	.04	5.68	4.05
2015			
Fourth quarter	.04	7.88	4.56
Third quarter	.04	8.57	6.37
Second quarter	.04	12.18	7.90
First quarter	.04	12.75	10.37
2014			
Fourth quarter	.04	12.00	10.12
Third quarter	.04	14.08	9.98
Second quarter	.04	9.83	8.51
First quarter	.04	8.99	7.63

At March 7, 2017, we had 197 shareholders of record of our common stock; this number does not include the shareholders holding stock in "street name." We estimate we have over 4,400 street name holders.

Equity Compensation Plan Information

Restricted Stock Units (RSUs)

Non-vested grants at January 1, 2014	164,000
Granted - weighted average share price on grant date was $8.29	1,195,500
Vested - weighted average share price on vesting date was $10.09	(310,000)
Forfeited	(7,500)
Non-vested grants at December 31, 2014	1,042,000
Granted - share price on grant date was $11.52	2,000
Vested - weighted average share price on vesting date was $7.42	(410,500)
Forfeited	(27,000)
Non-vested grants at December 31, 2015	606,500
Granted – weighted average share price on grant date was $6.84	414,000
Vested – weighted average share price on vesting date was $8.72	(271,500)
Forfeited	(16,000)
Non-vested grants at December 31, 2016 (1)	733,000

(1) 497,000 vest in 2017, 17,000 vest in 2018, and 219,000 vest in 2019

27

At December 31, 2016, we have 1,146,516 RSUs available for future issuance.

On the vesting dates, the shares that vested had a value of $2.4 million for 2016, $3.0 million for 2015 and $3,1 million for 2014. Under our RSU plan, participants are allowed to relinquish shares to pay for their required statutory income taxes.

The outstanding RSUs have a value of $6.1 million based on the March 8, 2017 closing stock price of $8.32.

For the years ended December 31, 2016, 2015 and 2014 stock based compensation was $2.5 million, $3.1 million, and $3.2 million, respectively. For 2017, based on existing RSUs outstanding, stock-based compensation expense will be $2.7 million.

Stock Options

We have no stock options outstanding.

Stock Bonus Plan

Our stock bonus plan was authorized in late 2009 with 250,000 shares. Currently, we have 86,383 shares available for future issuance.

Stock Performance

The following performance compares Hallador Energy (HNRG), the Russell 2000 Index, the SNL Coal Index, Alliance Resource Partners LP (NYSE: ARLP), Foresight Energy (NYSE: FELP), Peabody Energy (NYSE: BTUUQ).

The graph assumes that you invested $100 in our common stock and in each company and index at the closing price on December 31, 2011, that all dividends were reinvested, and that you continued to hold your investment through December 31, 2016.

Company/ Market/ Peer Group	2011	2012	2013	2014	2015	2016
Russell 2000 Index	$100.00	$116.35	$161.52	$169.43	$161.95	$196.45
Hallador Energy	$100.00	$91.92	$91.93	$126.52	$53.39	$109.57
Alliance Resource Partners LP	$100.00	$81.86	$115.79	$136.71	$47.18	$88.39
Foresight Energy LP				$100.00	$21.51	$39.43
SNL Coal Index	$100.00	$74.29	$72.70	$53.85	$13.48	$27.87
Peabody Energy Corp	$100.00	$81.37	$60.75	$24.65	$1.63	$1.06

ITEM 6. SELECTED FINANCIAL DATA.

For the years ended December 31,

(in thousands, except per share data)

	2016	2015	2014	2013	2012
Revenue:					
Coal sales	$278,924	$339,490	$233,902	$137,436	$131,370
Equity (loss) income – Savoy	(1,187)	(1,532)	5,272	5,827	2,039
Equity (loss) income - Sunrise Energy	(249)	(74)	248	629	167
Liability extinguishment				4,300	
Other	3,962	2,236	1,749	5,678	7,747
	281,450	340,120	241,171	153,870	141,323
Net income before impairment*	29,070	20,132	10,219	22,423	23,807
Asset impairment	$(16,560)				
Net income	$12,510	$20,132	$10,219	$22,423	$23,807
Net income per share					
Basic and diluted	$0.42	$0.68	$0.34	$0.78	$0.83
Cash dividends per share	$0.16	$0.16	$0.16	$0.12	$0.80
Balance Sheet Information (end of period)					
Total assets	$528,506	$540,378	$579,585	$259,199	$229,207
Total bank debt*	238,617	249,470	306,345	16,000	11,400

* Non-GAAP measurement. See Asset Impairment Review below and Note 3 to the consolidated financial statements.

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

Our consolidated financial statements should be read in conjunction with this discussion.

Overview

The largest portion of our business is devoted to coal mining in the State of Indiana through Sunrise Coal, LLC (a wholly owned subsidiary) serving the electric power generation industry. We also own a 30.6% equity interest in Savoy Energy, L.P., a private oil and gas exploration company with operations in Michigan, and a 50% interest in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana. We account for our investments in Savoy and Sunrise Energy using the equity method.

On August 29, 2014, we consummated the acquisition of Vectren Fuels, Inc. (VFI) for $311 million. See Note 2 to the financial statements. Vectren Fuels, headquartered in Evansville, Indiana, owned three underground coal mines in southwestern Indiana, including the Oaktown 1 and Oaktown 2 mines in Oaktown, Indiana, and the Prosperity Mine located in Petersburg, Indiana. The Prosperity Mine was idled on August 29, 2014. The two underground mines located near Oaktown, Indiana are seven miles south of our Carlisle underground mine.

Oaktown 1, Oaktown 2 and Carlisle are now one large underground mining complex representing 138 million tons of controlled reserves, with three portals, two wash plants and two rail facilities, located on the CSX. We anticipate total capacity for the three mines to be roughly 10.5 million tons annually. Additionally, the capacity of our Ace in the Hole mine is .4 million tons annually. Thus, our total mining capacity is 10.9 million tons annually.

For 2016, over 80% of our coal sales were to customers with large scrubbed coal-fired power plants in the State of Indiana. Our mines and coal reserves are strategically located in close proximity to our primary customers, which reduces transportation costs and thus provides us with a competitive advantage with respect to those customers; our closest customer's plant is 13 miles away and the farthest Indiana customer is 200 miles away. We have access to our primary customers directly through either the CSX railroad (NYSE: CSX) or through the Indiana Rail Road, majority owned by the CSX.

We see an increasing demand for coal produced in the Illinois Basin (ILB) in the future. Demand for coal produced in the ILB is expected to grow due to ILB coal having higher heating content than Powder River Basin (PRB) and lower cost structure than Central Appalachia (CAPP) coal. Many utilities are scrubbing to meet emission requirements beyond just sulfur compliance, even utilities that burn exclusively PRB. Once scrubbed, those utilities are usually capable of burning ILB coal. It is this trend of new scrubber installations coupled with rising CAPP cost structure that is leading to increased switching from CAPP coal to ILB coal.

The majority of our coal is sold to investment grade customers who have scrubbed power plants; thus, we expect to be supplying these plants for many years.

President Trump Promotes Coal

November 8, 2016

Donald Trump was elected President of the United States of America. We believe his administration will dramatically improve the regulatory environment in which we operate. Although President Trump has been in office for less than two months, we are encouraged by the pace that he has offered relief to the coal industry.

January 20, 2017

Donald Trump was inaugurated as the 45th President of the United States.

February 15, 2017

Both the U.S. House of Representatives and the Senate passed resolutions disapproving the Stream Protection Rule (SPR) under the Congressional Review Act ("CRA"). President Trump signed the resolution on February 16, 2017 and, pursuant to the CRA, the SPR "shall have no force or effect" and OSM cannot promulgate a substantially similar rule absent future legislation.

Currently, the Federal Surface Mining Control and Reclamation Act of 1977 (“SMCRA”) is implemented by each State’s respective State agency, which is the Department of Reclamation in Indiana. The SPR, would have mandated additional approvals from Federal Agencies, such as U.S. Fish and Wildlife. The rule would have also imposed additional baseline data collection, surface/groundwater monitoring, financial assurance requirements and numerous other requirements.

February 17, 2017

Scott Pruitt was confirmed as Administrator of the Environmental Protection Agency (“EPA”). As former Attorney General of the state of Oklahoma, he joined a coalition of state attorney generals in suing the EPA concerning the Clean Power Plan, the principal Obama-era policy aimed at reducing U.S. greenhouse gas emissions from the electricity sector.

February 28, 2017

President Trump signed an Executive Order regarding the “waters of the US” (WOTUS) rule. The order requires the EPA and the Army Corps of Engineers to review the WOTUS rule and publish a proposed rule that rescinds or revises the rule as appropriate and consistent with law, keeps the Nation’s navigable waters free from pollution, promotes economic growth, minimizes regulatory uncertainty, and shows due regard for the roles of the Congress and the States under the Constitution.

In President Trump’s first full official speech to a joint session of Congress, he stated “We’re going to stop the regulations that threaten the future and livelihood of our great coal miners.”

There have been additional comments from President Trump that indicate possible future actions that are encouraging and will be important to Hallador Energy Company and the U.S. energy sector.

Our Coal Contracts

We sell coal to the following customers: Duke Energy Corporation (NYSE: DUK), Hoosier Energy, an electric cooperative, Indianapolis Power & Light Company (IPL), a wholly-owned subsidiary of The AES Corporation (NYSE: AES), Northern Indiana Public Service Co. (NIPSCO), a wholly-owned subsidiary of NiSource Inc. (NYSE:NI) and Vectren Corporation (NYSE: VVC). We also deliver coal to two Florida utilities and one Kentucky utility. We believe these Florida sales are an indication of the trend of ILB coal replacing CAPP coal that has traditionally supplied the southeast markets.

On March 22, 2016, we completed the purchase of certain underground coal reserves and a coal sales agreement associated with Triad Mining, LLC's (Triad) Freelandville mining complex for $18.25 million. Triad is a wholly-owned subsidiary of Blackhawk Mining, LLC based in Lexington, Kentucky. The Freelandville complex is located in Sullivan and Knox Counties, Indiana. As part of the transaction, we purchased 14.2 million tons of proven coal reserves and associated advanced royalties in addition to rights under a coal sales agreement that extends through 2017. See Note 13 to our financial statements.

On December 12, 2016, we completed the purchase of another coal sales agreement from Triad's Log Creek mining complex for $4.1 million that extends through 2017. See Note 13 to our financial statements.

The table below (in thousands, except prices) shows our contracted tons. Some of our contracts contain language that allow our customers to increase or decrease tonnages throughout the year. The table represents the minimum and maximum tonnages we could deliver under existing contracts. In some cases, our customers are required to purchase their additional tonnage needs from us. We fully anticipate making additional sales.

	Minimum Tons to Be Sold			Maximum Tons to Be Sold			Estimated Prices @ Minimum
Year	Priced Tons	(Unpriced) Tons	Total Tons	Priced Tons	(Unpriced) Tons	Total Tons	Tons
2017	5,970		5,970	6,611		6,611	41.34
2018	1,894	810	2,704	2,791	1,210	4,001	44.53
2019	1,689	1,620	3,309	2,131	2,420	4,551	44.99
2020	1,000	2,009	3,009	1,000	3,001	4,001	48.36
2021		2,009	2,009		3,001	3,001	
2022		2,009	2,009		3,001	3,001	
2023		1,620	1,620		2,420	2,420	
2024		810	810		1,210	1,210	
	10,553	10,887	21,440	12,533	16,263	28,796	

Unpriced tons are firm commitments, meaning we are required to ship and our customer is required to receive said tons through the duration of the contract. The contracts provide mechanisms for establishing a market-based price. As set forth in the table above, we have 11-16 million tons committed but unpriced through 2024.

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. Typically, customers enter into coal supply agreements to secure reliable sources of coal at predictable prices while we seek stable sources of revenue to support the investments required to open, expand and maintain, or improve productivity at the mines needed to supply these contracts. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers.

Asset Impairment Review

In December 2016, the deterioration of the North end of the Carlisle mine, coupled with lower coal prices led us to determine that the Northern end of the Carlisle mine no longer could be safely and profitably mined. Thus, the decision was made to seal off the North end of the mine. Sealing will be completed in the 1st quarter of 2017. We identified specific assets totaling $16.6 million ($15.1 million of property and equipment and $1.5 million of advanced royalties) that were written off in 2016. After the impairment, the Carlisle assets had an aggregate carrying value of $118 million at December 31, 2016. We conducted a review of the Carlisle mine assets and determined that no further impairment charge was necessary. If, in future periods, we reduce our estimate of the future net cash flows attributable to the Carlisle Mine, it may result in additional future impairment of such assets and such charges could be significant. None of our other assets are considered impaired.

Current Projects

All of our underground coal reserves are high sulfur (4.5# – 6.5#) with a BTU content in the 11,200 -11,500 range. Our reserves have lower chlorine (<0.12%) than average ILB reserves of 0.22%. Much of the ILB's new production is located in Illinois and possesses chlorine content in excess of .30%. The relatively low chlorine content of our reserves is attractive to buyers given their desire to limit the corrosive effects of chlorine in their power plants.

As discussed below, the Ace surface mine is low sulfur (1.9#) with a BTU content of 10,800 -11,400. We have no met coal reserves, only steam (thermal) coal reserves. Below is a discussion of our current projects preceded by a table of our coal reserves. Only tons greater than 4' in thickness are included in our underground reserves.

Reserve Table - Controlled Tons (in millions):

		2016 Year-End Reserves					
	Tons Sold	Annual Capacity	Proven	Probable	Total	Sulphur #	BTU
Oaktown 1 (assigned)	3.895	4.0	41.8	15.1	56.9	5.5	11,350
Oaktown 2 (assigned)	2.075	4.0	39.3	14.2	53.5	4.8	11,500
Carlisle (assigned)	.013	2.5	21.8	5.5	27.3	4.6	11,480
Ace in the Hole (assigned)	.334	0.4	1.3		1.3	1.9	11,200
Bulldog (unassigned)			19.6	16.2	35.8	4.5	11,320
Total	6.317	10.9	123.8	51.0	174.8		

Assigned	139.0
Unassigned	35.8
	174.8

Oaktown 1 Mine (underground) – Assigned

We have 56.9 million controlled, saleable tons of the Indiana #V coal seam, including 14.2 million tons acquired from Triad in 2016. We began 2016 with 40.6 million tons controlled. The remainder of the increase relates to new drilling, new leases, and newly accessible owned coal due to the Triad acquisition. See Note 13 in our financial statements. Oaktown 1 reserves are located in Knox County, IN.

Access to the Oaktown 1 mine is via a 90-foot-deep box cut and a 2,200-foot slope, reaching coal in excess of 375 feet below the surface.

Oaktown 2 Mine (underground) – Assigned

We have 53.5 million controlled, saleable tons of the Indiana #V coal seam. We began 2016 with 69.3 million controlled tons. Approximately 14.2 million controlled tons have been removed from our controlled reserves due to geologic conditions, new drilling, and mine plan changes. Oaktown 2 reserves are located in both Knox County, Indiana and Lawrence County, Illinois.

Access to the Oaktown 2 mine is via an 80-foot-deep box cut and a 2,600-foot slope, reaching coal in excess of 400 feet below the surface.

Our underground mines are room and pillar mines that utilize developed entries for ventilation and transportation. Continuous miners extract coal from rooms by removing coal from the seam, leaving pillars to support the roof. Coal haulers are used to transport coal to a conveyor belt for transport to the surface. The two Oaktown mines are separated by a sandstone channel. The coal seam thickness ranges from 4 feet to over 9 feet. The Oaktown mines share the same wash plant which is rated at 1,800 tons per hour. The two mines are connected to a rail loadout that can store two 120 car trains at once and is serviced by the CSX Railroad and Indiana Railroad. Coal is also transported via truck to customers.

Carlisle Mine (underground) – Assigned

After a reduction of 16.6 million tons due to the sealing of the north end of the mine, our coal reserves at December 31, 2016 assigned to the Carlisle Mine were 27.3 million tons. We began 2016 with 43.9 million controlled tons. The mine is located near the town of Carlisle, Indiana in Sullivan County and became operational in January 2007. The coal is accessed with a slope to a depth of 340'. The coal is mined in the Indiana #V coal seam which is highly volatile bituminous coal and has been extensively mined by underground and surface methods in the general area. The coal thickness in the project area is 4' to 7'. The Carlisle Mine is completely developed, but is currently idle.

Ace in the Hole Mine (Ace) (surface) – Assigned

The Ace mine is near Clay City, Indiana in Clay County and 42 road miles northeast of the Carlisle Mine. We control 1.3 million tons of proven coal reserves of which we own ..9 million tons in fee. We mine two primary seams of low sulfur coal which make up 1.2 million of the 1.3 million tons controlled. Both of the primary seams are low sulfur (<2# SO_2). Mine development began in late December 2012, and we began shipping coal in late August 2013. We truck low sulfur coal from Ace to Carlisle and/or Oaktown to blend with high sulfur coal. Many utilities in the southeastern U.S. have scrubbers with lower sulfur limits (4.5# SO_2) which cannot accept the higher sulfur contents of the ILB (4.5# - 6.5# SO_2). Blending high sulfur coal to a lower sulfur specification enables us to market our high sulfur coals to more customers. We expect the maximum capacity of Ace to be 400,000 tons annually.

The Ace mine is a multi-seam open pit strip mine. The majority of the seams are sold raw, but some of the seams will be washed prior to sales depending on quality. To convert the tons sold raw the in-place tonnage is taken times a pit recovery of 94% based on seam thickness. To convert the tons sold washed the in-place tonnage is taken times a pit recovery based on seam thickness then reduced by the projected plant recovery of 72%.

Bulldog Mine (underground) – Unassigned

We have leased roughly 19,300 acres in Vermilion County, Illinois near the village of Allerton. Based on our reserve estimates we currently control 35.8 million tons of coal reserves. A considerable amount of our leased acres has yet to receive any exploratory drilling, thus we anticipate our controlled reserves to grow as we continue drilling. Our formal permit was filed with the State of Illinois in 2012. It is our estimate that our permit will be approved in 2017.

Full-scale mine development will not commence until we have a sales commitment. We estimate the costs to develop this mine to be $150 million at full capacity of three million tons annually.

Unassigned reserves represent coal reserves that would require new mineshafts, mining equipment, and plant facilities before operations could begin on the property. The primary reason for this distinction is to inform investors which coal reserves will require substantial capital expenditures before production can begin.

Below is a map that shows the locations of our mines.

Railroad Legend:

CSX – CSX Railroad

INRD – Indiana Rail Road

ISRR – Indiana Southern Railroad

NS – Norfolk Southern Railway

Mine and Wash Plant Recovery and Capacity

	Mine recovery	Wash plant recovery*	Wash Plant Capacity (Clean Tons)
Oaktown 1	49 %	81 %	8.0 million**
Oaktown 2	49 %	81 %	
Carlisle	53 %	81 %	3.5 million
Bulldog	45 %	77 %	

* Does not include out-of-seam material extracted during the mining process.

** Oaktown 1 and Oaktown 2 share the wash plant.

Liquidity and Capital Resources

Contractual Obligations (in thousands)	Total	2017	2018 - 2019	2020 and thereafter
Long-term debt (due end of 2019)	$238,617	$30,625	$ 207,992	
Future interest obligations	28,100	11,900	16,200	
Reclamation obligations	13,260	145	184	$ 12,931

$279,977	$42,670	$ 224,376	$ 12,931

As set forth in our Statement of Cash Flows, cash provided by operations was $61 million for 2016. This amount was adequate to fund our capital expenditures for coal properties (less our acquisitions from Triad), our debt service requirements and our dividend. Our capex budget for 2017 is $30 million, of which $17 million is for maintenance capex. Cash from operations for 2017 should again fund our maintenance capital expenditures, debt service and our dividend.

On March 18, 2016, we executed an amendment to our credit agreement with PNC Bank, as administrative agent for our lenders. The primary purpose of the amendment was to increase liquidity and maintain compliance through the maturity of the agreement in August 2019. The revolver was reduced from $250 million to $200 million and the term loan remains the same. Our debt at December 31, 2016 was $239 million (term-$102 million, revolver-$137 million). In addition, a maximum annual capex of $30 million was included.

The amended credit facility increased the maximum leverage ratio (total funded debt/ trailing 12 months EBITDA) from 2.75X to those listed below:

Fiscal Periods Ended/Ending	Ratio
September 30, 2016 through March 31, 2017	4.50 X
June 30, 2017 through March 31, 2018	4.25 X
June 30, 2018 and September 30, 2018	4.00 X
December 31, 2018	3.75 X
March 31, 2019 and June 30, 2019	3.50 X

The fixed charge coverage ratio was also changed to a debt service coverage ratio and requires a minimum of 1.25X through the maturity of the credit facility. The amendment defines the debt service coverage as trailing 12 months EBITDA/annual debt service. As of December 31, 2016, we have additional borrowing capacity of $63 million and total liquidity of $82 million.

At December 31, 2016, our leverage ratio was 2.95 and our debt service coverage ratio was 2.11. Therefore, we were in compliance with those two ratios.

Other than our surety bonds for reclamation, we have no material off-balance sheet arrangements. Included in the contractual obligations table are reclamation obligations of $13.3 million, which are presented as asset retirement obligations in our accompanying balance sheets. We have surety bonds covering ARO, totaling $24 million, in the event we are not able to perform reclamation.

Capital Expenditures (capex)

For 2016, our capex was $19.8 million allocated as follows (in millions):

Oaktown - maintenance capex	$9.6
Oaktown - investment	8.4
Other projects	1.8
Capex per the Cash Flow Statement	$19.8

Results of Operations

The following table presenting our quarterly results of operations should be read in conjunction with the consolidated financial statements and related notes included in Item 8 of their Annual Report on the Form 10-K. We have prepared the unaudited information on the same basis as our audited consolidated financial statements. Our operating results for any quarter are not necessarily indicative of results for any future quarters or for a full year.

The following table presents our unaudited quarterly results of operations for the eight quarters ended December 31, 2016. This table includes all adjustments, consisting only of normal recurring adjustments, that we consider necessary for fair presentation of our consolidated operating results for the quarters presented.

	2015 Mar 31	Jun 30	Sep 30	Dec 31	2016 Mar 31	Jun 30	Sep 30	Dec 31
Revenue:								
Coal sales	$97,073	$95,323	$81,332	$65,762	$75,795	$66,274	$65,360	$71,495
Equity income (loss) in equity method investments	176	(190)	(72)	(1,520)	(400)	174	(80)	(1,130)
Other	752	120	753	611	490	2,116	487	869
Total revenue	98,001	95,253	82,013	64,853	75,885	68,564	65,767	71,234
Costs and expenses:								
Operating cost and expenses	66,152	68,280	56,995	46,470	49,777	45,397	46,940	50,663
DD&A	11,338	10,770	10,648	11,186	9,182	9,056	7,942	9,385
Coal exploration costs	708	492	381	458	419	395	354	505
SG&A	3,344	3,080	3,003	3,190	2,762	2,729	2,585	2,444
Interest	5,456	3,323	5,176	2,100	5,845	4,752	2,861	2,413
Asset impairment								16,560
Total cost and expenses	86,998	85,945	76,203	63,404	67,985	62,329	60,682	81,970
Income before income taxes	11,003	9,308	5,810	1,449	7,900	6,235	5,085	(10,736)
Less income taxes:								
Current	1,416	(865)	680	(1,245)	768	(768)	(270)	103
Deferred	1,996	3,320	(14)	2,150	970	1,150	1,033	(7,012)
Total income taxes	3,412	2,455	666	905	1,738	382	763	(6,909)
Net income	$7,591	$6,853	$5,144	$544	$6,162	$5,853	$4,322	$(3,827)
Net income per share:								
Basic and diluted	$0.25	$0.23	$0.17	$0.02	$0.21	$0.19	$0.14	$(0.13)
Weighted average shares outstanding:								
Basic and diluted	28,962	29,024	29,044	29,090	29,251	29,251	29,252	29,287

Oaktown’s cash costs were $28.02/ton and $26.61/ton for the year and quarter ending December 31, 2016, respectively. We see Oaktown’s costs ranging from $28 to $30 for 2017. Going forward we expect our SG&A to be $11 million annually and costs associated with Prosperity and Carlisle to be $7 million annually.

The column for the 3rd and 4th quarter of 2014 in the table below includes the mines acquired from Vectren on August 29, 2014.

36

Quarterly coal sales and cost data (in 000's, except for per ton data and wash plant recovery percentage):

	1st 2016	2nd 2016	3rd 2016	4th 2016	T4Qs
Tons sold	1,629	1,464	1,485	1,739	6,317
Coal sales	$ 75,795	$ 66,274	$ 65,360	$ 71,495	$ 278,924
Average price/ton	46.53	45.27	44.01	41.11	44.15
Wash plant recovery in %	65	63	68	67	66
Operating costs	$ 49,777	$ 45,397	$ 46,940	$ 50,663	$ 192,777
Average cost/ton	30.56	31.01	31.61	29.13	30.52
Margin	26,018	20,877	18,420	20,832	86,147
Margin/ton	15.97	14.26	12.40	11.98	13.64
Capex	6,053	1,822	3,935	8,022	19,832
Maintenance capex	2,984	904	1,709	5,301	10,898
Maintenance capex/ton	1.83	.62	1.15	3.05	1.73

	1st 2015	2nd 2015	3rd 2015	4th 2015	T4Qs
Tons sold	2,146	2,078	1,791	1,432	7,447
Coal sales	$ 97,073	$ 95,323	$ 81,332	$ 65,762	$ 339,490
Average price/ton	45.23	45.87	45.41	45.92	45.59
Wash plant recovery in %	67	69	69	64	67
Operating costs	$ 66,152	$ 68,280	$ 56,995	$ 46,470	$ 237,897
Average cost/ton	30.83	32.86	31.82	32.45	31.95
Margin	30,921	27,043	24,337	19,292	101,593
Margin/ton	14.40	13.01	13.59	13.47	13.64
Capex	8,250	14,789	4,070	4,058	31,167
Maintenance capex	6,685	13,323	1,816	1,047	22,871
Maintenance capex/ton	3.12	6.41	1.01	.73	3.07

	1st 2014	2nd 2014	3rd 2014	4th 2014	T4Qs
Tons sold	776	847	1,500	2,275	5,398
Coal sales	$ 33,016	$ 36,130	$ 64,764	$ 99,992	$ 233,902
Average price/ton	42.55	42.66	43.18	43.95	43.33
Wash plant recovery in %	66	68	64	67	66
Operating costs	$ 23,005	$ 26,096	$ 52,588	$ 68,002	$ 169,691
Average cost/ton	29.65	30.81	35.06	29.89	31.44
Margin	10,011	10,034	12,176	31,990	64,211
Margin/ton	12.90	11.85	8.12	14.06	11.89
Capex	2,936	6,190	5,200	11,509	25,835
Maintenance capex	2,650	3,974	4,756	11,162	22,542
Maintenance capex/ton	3.41	4.69	3.17	4.91	4.18

2016 v. 2015

For 2016, we sold 6,317,000 tons at an average price of $44.15/ton. For 2015, we sold 7,447,000 tons at an average price of $45.59/ton.

Operating costs and expenses averaged $30.52/ton in 2016 compared to $31.95 in 2015. Our Sunrise Coal employees totaled 742 at December 31, 2016 compared to 740 at December 31, 2015.

SG&A costs were higher in 2015 due to amortization of RSUs and accruals of bonuses related to our Vectren Fuels acquisition in 2014. SG&A as a percentage of coal revenue remained consistent at 3.8% in 2016 and 3.7% in 2015.

We incurred an asset impairment of $16.6 million due to our decision to seal the north portal of the Carlisle mine. We determined that the North end had deteriorated to the point that it could no longer be safely and profitably mined.

At the beginning of 2016, we changed from the straight-line method to the units-of-production method in computing the depreciation for continuous miners. This change in estimate reduced our DD&A expense for the year ended December 31, 2016 by $2.6 million. This change better reflects the usage of our continuous miners considering our reduced production in 2016. Due to idle equipment at Carlisle, we stopped depreciating specific underground equipment resulting in a $4.4 million reduction in depreciation for the year ending December 31, 2016.

2015 v. 2014

For 2015, we sold 7,447,000 tons at an average price of $45.59/ton. For 2014, we sold 5,398,000 tons at an average price of $43.33/ton. The increase is attributable to the Vectren acquisition in late August 2014.

Operating costs and expenses averaged $31.95/ton in 2015 compared to $31.44 in 2014. Our Indiana employees totaled 740 at December 31, 2015 compared to 1,018 at December 31, 2014.

There was no material increase in SG&A.

2014 v. 2013

For 2014, we sold 5,398,000 tons at an average price of $43.33/ton. For 2013, we sold 3,188,000 tons at an average price of $43.11/ton. The increase is attributable to the Vectren acquisition.

Operating costs and expenses averaged $31.44/ton in 2014 compared to $29.52 in 2013. The reasons for the increase were primarily due to the Vectren acquisition. Our Indiana employees totaled 1,018 at December 31, 2014 compared to 373 at December 31, 2013.

SG&A expense increased significantly for several reasons: (i) contributions to political candidates and PACs who support the coal mining industry increased by $200,000; (ii) stock based compensation increased by $850,000; (iii) audit and tax fees increased by $310,000; (iv) employee related costs increased by $700,000 and (v) ongoing expenses resulting from the VFI acquisition was $1 million. We also paid $1 million in performance bonuses during December 2014 relating to the VFI acquisition.

MSHA Reimbursements

Some of our legacy coal contracts allow us to pass on to our customers certain costs incurred resulting from changes in costs to comply with mandates issued by MSHA or other government agencies. We do not recognize any revenue until our customers have notified us that they accept the charges.

We submitted our incurred costs for 2012 in June 2015 and received $1.75 million from one of our customers in June 2016. We expect to receive a similar amount from another customer during Q1 2017. As stated above we do not record such reimbursements as revenue until they have been agreed to by our customers.

Incurred costs for 2013 – 2016 will be submitted in 2017. 2013 costs are expected to be between $2 million and $2.7 million. Such reimbursable costs for 2014 through 2016 are not expected to be material.

Income Taxes

Our effective tax rate (ETR) for 2016 was (48)% compared to 27% for 2015 and 4.5% for 2014. The negative ETR in 2016 is due to the combination of the reduction in book income before taxes because of the asset impairment expense, permanent tax benefits of statutory depletion in excess of tax basis in the mining properties, the captive insurance company effects, and stock based compensation expense. The low ETR for 2014 was due primarily to the reduction in the Indiana state income tax rate.

In March 2014, the State of Indiana passed legislation to reduce over the next eight years the corporate state income tax rate from 7.5% to 4.9% by 2022. We used a weighted rate of 6% for 2014. This resulted in us making a one-time reduction of $1.4 million to our deferred income tax liability account and a one-time credit to our income tax expenses for the same amount resulting in an unsustainable low effective tax rate (ETR) of 4.5% for 2014.

30.6% Ownership in Savoy

Our share of Savoy's income dropped due to the precipitous drop in oil prices.In addition, Savoy recorded to the 100% a $2.0 million and $2.6 million impairment charge in the 4th quarter of 2016 and 2015, respectively.

Our ownership also changed from 40.8% to 30.6% in 2016. See Note 12.

Critical Accounting Estimates

We believe that the estimates of our coal reserves, our deferred tax accounts, our business acquisitions, and the estimates used in our impairment analysis are our only critical accounting estimates. The reserve estimates are used in the DD&A calculation and in our internal cash flow projections. If these estimates turn out to be materially under or over-stated, our DD&A expense and impairment test may be affected.

We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items. The fair value of our interest rate swaps is determined using a discounted future cash flow model based on the key assumption of anticipated future interest rates.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position.

Yorktown Distributions

As previously disclosed, Yorktown Energy Partners and its affiliated partnerships (Yorktown) have made 14 distributions to their numerous partners totaling 9.75 million shares since May 2011. In the past, these distributions were made soon after we filed our Form 10-Qs and Form 10-Ks. Currently they own 5.45 million shares of our stock representing about 18.5% of total shares outstanding. Yorktown last distributed shares in November 2016.

We have been informed by Yorktown that they have not made any determination as to the disposition of their remaining Hallador stock. While we do not know Yorktown’s ultimate strategy to realize the value of their Hallador investment for their partners, we expect that over time such distributions will increase our liquidity and float.

If we are advised of another Yorktown distribution, we will timely report such on a Form 8-K.

New Accounting Standards

See “Item 8. Financial Statements and Supplementary Data – Note 1. Summary of Significant Accounting Policies” for a discussion of new accounting standards.

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

Substantially all our business is conducted in Indiana, so we have no foreign exchange currency risk.

We have exposure to price risk for supplies that are used directly or indirectly in the normal course of coal production such as steel, electricity and other supplies. We manage our risk for these items through strategic sourcing contracts for normal quantities required by our operations. We do not utilize any commodity price-hedges or other derivatives related to these risks

Borrowings under our credit agreement are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates. As disclosed in Note 4 to our financial statements we entered into swap agreements to fix the LIBOR component of the interest rate to achieve an effective fixed rate of no greater than 5% on the original term loan balance and on $100 million of the revolver. Quarterly, we mark-to-market the value of the swaps. For 2016, the change in value was $637,000 and not considered material. As short-term interest rates rise (especially the two-year U.S. treasury note) the value of the swap increases and as they fall the value decreases.

We expect to continue selling a significant portion of our coal under supply agreements with terms of one year or longer. Typically, customers enter into coal supply agreements to secure reliable sources of coal at predictable prices while we seek stable sources of revenue to support the investments required to open, expand and maintain, or improve productivity at the mines needed to supply these contracts. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

Hallador Energy Company

Denver, Colorado

We have audited the accompanying consolidated balance sheets of Hallador Energy Company (the "Company") as of December 31, 2016, and 2015, and the related consolidated statements of comprehensive income, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2016. We also have audited the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hallador Energy Company as of December 31, 2016, and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, Hallador Energy Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/s/ EKS&H LLLP

March 10, 2017

Denver, Colorado

Consolidated Balance Sheet

As of December 31,

(in thousands, except per share data)

	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$9,788	$15,930
Certificates of deposit	7,315	
Marketable securities	1,763	1,343
Accounts receivable	22,307	16,675
Prepaid income taxes		5,312
Coal inventory	10,100	14,915
Parts and supply inventory	10,091	11,255
Purchased coal contracts	8,922	
Prepaid expenses	9,647	1,185
Total current assets	79,933	66,615
Coal properties, at cost:		
Land and mineral rights	126,303	116,209
Buildings and equipment	339,999	347,963
Mine development	126,037	131,027
Total coal properties, at cost	592,339	595,199
Less - accumulated DD&A	(169,579)	(149,964)
Total coal properties, net	422,760	445,235
Investment in Savoy	7,577	12,365
Investment in Sunrise Energy	4,122	4,747
Other assets (Note 8)	14,114	11,416
Total assets	$528,506	$540,378
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of bank debt, net	$28,796	$24,856
Accounts payable and accrued liabilities	16,956	26,184
Total current liabilities	45,752	51,040
Long-term liabilities:		
Bank debt, net	204,944	219,502
Deferred income taxes	45,174	49,033
Asset retirement obligations	13,260	12,231
Other	2,486	1,752
Total long-term liabilities	265,864	282,518
Total liabilities	311,616	333,558
Stockholders' equity:		
Preferred Stock, $.10 par value, 10,000 shares authorized; none issued		
	294	292

Common stock, $.01 par value, 100,000 shares authorized; 29,413 and 29,251 shares outstanding, respectively		
Additional paid-in capital	93,816	92,275
Retained earnings	122,052	114,341
Accumulated other comprehensive income (loss)	728	(88)
Total stockholders' equity	216,890	206,820
Total liabilities and stockholders' equity	$528,506	$540,378

See accompanying notes.

43

Consolidated Statement of Comprehensive Income

For the years ended December 31,

(in thousands, except per share data)

	2016	2015	2014
Revenue:			
Coal sales	$278,924	$339,490	$233,902
Equity income (loss) - Savoy	(1,187)	(1,532)	5,272
Equity income (loss) - Sunrise Energy	(249)	(74)	248
Other (Note 8)	3,962	2,236	1,749
Total revenue	281,450	340,120	241,171
Costs and expenses:			
Operating costs and expenses	192,777	237,897	169,691
DD&A	35,565	43,942	29,262
Coal exploration costs	1,673	2,039	2,362
SG&A	10,520	12,617	12,039
Interest (1)	15,871	16,055	9,059
Vectren deal costs (Note 2)			8,057
Asset impairment (Note 3)	16,560		
Total costs and expenses	272,966	312,550	230,470
Income before income taxes	8,484	27,570	10,701
Less income tax (benefits) expense:			
Current	(167)	(14)	2,205
Deferred	(3,859)	7,452	(1,723)
Total income tax (benefits) expense	(4,026)	7,438	482
Net income*	$12,510	$20,132	$10,219
Net income per share (Note 10):			
Basic and diluted	$0.42	$0.68	$0.34
Weighted average shares outstanding:			
Basic and diluted	29,260	29,031	28,776

*There is no material difference between net income and comprehensive income.

(1) Included in interest expense is the change in the estimated fair value of our interest rate swaps. Such amounts were $(637), $159 and $658 for 2016, 2015 and 2014, respectively. 2014 also includes $1 million for expensing deferred financing costs relating to our old credit agreement.

See accompanying notes.

44

Consolidated Statement of Cash Flows

For the years ended December 31,

(in thousands)

	2016	2015	2014
Operating activities:			
Net income	$12,510	$20,132	$10,219
Deferred income taxes	(3,859)	7,452	(1,723)
Equity (income) loss – Savoy and Sunrise Energy	1,436	1,606	(5,520)
Cash distributions from Savoy and Sunrise Energy	3,977		8,109
DD&A	35,565	43,942	29,262
Asset impairment	16,560		
Loss on sale of assets	197		
Change in fair value of interest rate swaps	(637)	159	658
Amortization and write off of deferred financing costs	2,325	1,394	1,572
Amortization of purchased coal contracts	1,593		
Accretion of ARO	1,029	498	534
Stock-based compensation	2,539	3,134	3,220
Taxes paid on vesting of RSUs	(1,098)	(1,029)	(1,067)
Change in current assets and liabilities:			
Accounts receivable	(5,632)	10,627	(324)
Coal inventory	4,815	4,807	6,540
Parts and supply inventory	1,164	3,664	1,083
Prepaid income taxes	5,312	448	(160)
Accounts payable and accrued liabilities	(11,193)	(1,686)	1,409
Other	(5,685)	(492)	2,054
Cash provided by operating activities	60,918	94,656	55,866
Investing activities:			
Capital expenditures	(19,832)	(31,167)	(25,835)
Purchase of Freelandville and Log Creek assets	(22,358)		
Purchase of certificates of deposit	(7,315)		
Vectren acquisition			(311,453)
Other	189	641	
Cash used in investing activities	(49,316)	(30,526)	(337,288)
Financing activities:			
Payments of bank debt	(34,855)	(56,875)	(59,655)
Bank borrowings	24,000		350,000
Deferred financing costs	(2,090)		(6,884)
Dividends	(4,799)	(4,794)	(4,798)
Cash used in financing activities	(17,744)	(61,669)	278,663
Increase (decrease) in cash and cash equivalents	(6,142)	2,461	(2,759)
Cash and cash equivalents, beginning of year	15,930	13,469	16,228
Cash and cash equivalents, end of year	$9,788	$15,930	$13,469

Cash paid for interest	$12,708	$14,149	$5,008
Cash (received) paid for income taxes, net	(5,594)	(956)	2,334
Increase in ARO			6,550
Capital expenditures included in accounts payable	1,616	804	748

See accompanying notes.

45

Consolidated Statement of Stockholders' Equity

(in thousands)

	Common Shares	Common Stock	Additional Paid-In Capital	Retained Earnings	AOCI*	Total
Balance January 1, 2014	28,751	$ 287	$ 87,872	$ 93,582	$ 379	$ 182,120
Stock-based compensation	7		3,220			3,220
Stock issued on vesting of RSUs	310	2				2
Taxes paid on vesting of RSUs	(106)		(1,067)			(1,067)
Dividends				(4,798)		(4,798)
Net income				10,219		10,219
Other			193		(14)	179
Balance December 31, 2014	28,962	289	90,218	99,003	365	189,875
Stock-based compensation	14		3,134			3,134
Stock issued on vesting of RSUs	411	3				3
Taxes paid on vesting of RSUs	(136)		(1,029)			(1,029)
Dividends				(4,794)		(4,794)
Net income				20,132		20,132
Other			(48)		(453)	(501)
Balance December 31, 2015	29,251	292	92,275	114,341	(88)	206,820
Stock-based compensation			2,539			2,539
Stock issued on vesting of RSUs	272	2				2
Taxes paid on vesting of RSUs	(126)		(1,098)			(1,098)
Dividends				(4,799)		(4,799)
Net income				12,510		12,510
Other	16		100		816	916
Balance December 31, 2016	29,413	$ 294	$ 93,816	$ 122,052	$ 728	$ 216,890

*Accumulated Other Comprehensive Income (loss)

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

The consolidated financial statements include the accounts of Hallador Energy Company (the Company) and its wholly owned subsidiary Sunrise Coal, LLC (Sunrise) and Sunrise's wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. We are engaged in the production of steam coal from mines located in western Indiana. We own a 30.6% equity interest in Savoy Energy, L.P., a private oil and gas company that has operations in Michigan and a 50% interest in Sunrise Energy, LLC, a private entity engaged in natural gas operations in the same vicinity as the Carlisle Mine.

Reclassification

To maintain consistency and comparability, certain amounts in the financial statements have been reclassified to conform to current year presentation.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs (including depreciation thereto) and overhead.

Advance Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced. Advance royalties are included in other assets.

Coal Properties

Coal properties are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Expenditures that extend the useful lives or increase the productivity of the assets are capitalized. The cost of maintenance and repairs that do not extend the useful lives or increase the productivity of the assets are expensed as incurred. Other than land and most mining equipment, coal properties are depreciated using the units-of-production method over the estimated recoverable reserves. Most surface and underground mining equipment is depreciated using estimated useful lives ranging from three to twenty-five years. At the beginning of 2016, we changed from the straight-line method to the units-of-production method in computing the depreciation for continuous miners. This change in estimate reduced our DD&A expense for the year ended December 31, 2016 by $2.6 million. Due to idle equipment at Carlisle, we stopped depreciating specific underground equipment resulting in a $4.4 million reduction in depreciation for the year ending December 31, 2016.

If facts and circumstances suggest that a long-lived asset may be impaired, the carrying value is reviewed for recoverability. If this review indicates that the carrying value of the asset will not be recoverable through estimated undiscounted future net cash flows related to the asset over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its estimated fair value.

Mine Development

Costs of developing new coal mines, including asset retirement obligation assets, or significantly expanding the capacity of existing mines, are capitalized and amortized using the units-of-production method over estimated recoverable reserves.

Asset Retirement Obligations (ARO) - Reclamation

At the time they are incurred, legal obligations associated with the retirement of long-lived assets are reflected at their estimated fair value, with a corresponding charge to mine development. Obligations are typically incurred when we commence development of underground and surface mines, and include reclamation of support facilities, refuse areas and slurry ponds.

Obligations are reflected at the present value of their future cash flows. We reflect accretion of the obligations for the period from the date they are incurred through the date they are extinguished. The ARO assets are amortized using the units-of-production method over estimated recoverable (proved and probable) reserves. We are using discount rates ranging from 5.5% to 10%. Federal and state laws require that mines be reclaimed in accordance with specific standards and approved reclamation plans, as outlined in mining permits. Activities include reclamation of pit and support acreage at surface mines, sealing portals at underground mines, and reclamation of refuse areas and slurry ponds.

We review our ARO at least annually and reflect revisions for permit changes, changes in our estimated reclamation costs and changes in the estimated timing of such costs.

The table below (in thousands) reflects the changes to our ARO:

	2016	2015
Balance, beginning of year	$12,231	$12,074
Accretion	1,029	498
Additions		
Other		(341)
Balance, end of year	$13,260	$12,231

Statement of Cash Flows

Cash equivalents include investments with maturities when purchased of three months or less.

Income Taxes

Income taxes are provided based on the liability method of accounting. The provision for income taxes is based on pretax financial income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting and principally relate to differences in the tax basis of assets and liabilities and their reported amounts, using enacted tax rates in effect for the year in which differences are expected to reverse.

Net Income per Share

Basic net income per share is computed on the basis of the weighted average number of shares of common stock outstanding during the period. Diluted net income per share is computed on the basis of the weighted average number of shares of common stock plus the effect of dilutive potential common shares outstanding during the period. Dilutive potential common shares include restricted stock units and are included in basic net income per share, using the two-class method.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual amounts could differ from those estimates. The most significant estimates included in the preparation of the financial statements relate to: (i) fair value estimates relating to business combinations, (ii) deferred income tax accounts, (iii) coal reserves, and (iv) estimates used in our impairment analysis.

Derivatives

Our interest swaps had a net value of $.2 million, including $.3 million classified in other assets and $.5 million in accounts payable and accrued liabilities on our consolidated balance sheet. Notional values of the two interest rate swaps were $125 million and $60 million as of December 31, 2016.

Business Combinations

We account for business combinations using the purchase method of accounting. The purchase method requires us to determine the fair value of all acquired assets, including identifiable intangible assets and all assumed liabilities. The total cost of acquisitions is allocated to the underlying identifiable net assets, based on their respective estimated fair values. Determining the fair value of assets acquired and liabilities assumed requires management's judgment and the utilization of independent valuation experts, and often involves the use of significant estimates and assumptions, including assumptions with respect to future cash inflows and outflows, discount rates and asset lives, among other items.

Revenue Recognition

We recognize revenue from coal sales at the time risk of loss passes to the customer at contracted amounts and amounts are deemed collectible.

Long-term Contracts

As of December 31, 2016, we are committed to supply to our customers a maximum of 29 million tons of coal through 2024 of which 13 million tons are priced.

For 2016, our five largest customers were Vectren, Hoosier, OUC, IPL and NIPSCO. We derived 90% of our total revenue from these customers. Each of these customers represented at least 10% of our total revenue.

For 2015, our four largest customers were IPL, NIPSCO, Vectren, and Hoosier. We derived 82% of our total revenue from these customers. Each of these customers represented at least 10% of our total revenue.

For 2014, our four largest customers were IPL, Vectren, Hoosier, and Duke. We derived 71% of our total revenue from these customers. Each of these customers represented at least 10% of our total revenue.

We are paid every two to four weeks and do not expect any credit losses.

Stock-based Compensation

Stock-based compensation is measured at the grant date based on the fair value of the award and is recognized as expense over the applicable vesting period of the stock award (generally two to four years) using the straight-line method.

New Accounting Standards Issued and Adopted

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest ("ASU 2015-03"). ASU 2015-03 changes the classification and presentation of debt issuance costs by requiring debt issuance costs to be reported as a direct deduction from the face amount of the debt liability rather than an asset. Amortization of the costs is reported as interest expense. The amendment does not affect the current guidance on the recognition and measurement of debt issuance costs. ASU 2015-03 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2015 and is applied retrospectively to each period presented. The adoption of ASU 2015-03 did not have a material impact on our consolidated financial statements. See Note 4.

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 provides guidance on management's responsibility in evaluating whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter with early adoption permitted. The adoption of ASU 2014-15 did not have a material impact on our consolidated financial statements.

In March 2016, the FASB issued ASU 2016-09, Compensation–Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). ASU 2016-09 simplifies the accounting for several aspects of share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, flexibility in the accounting for forfeitures and classification on the statement of cash flows. ASU 2016-09 is effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods, with early adoption permitted. The adoption of ASU 2016-09 did not have a material impact on our consolidated financial statements.

New Accounting Standards Issued and Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842) ("ASU 2016-02"). ASU 2016-02 increases transparency and comparability among organizations by requiring lessees to record right-to-use assets and corresponding lease liabilities on the balance sheet and disclosing key information about lease arrangements. The new guidance will classify leases as either finance or operating (similar to current standard's "capital" or "operating" classification), with classification affecting the pattern of income recognition in the statement of income. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We are currently in the process of accumulating all contractual lease arrangements in order to determine the impact on our financial statements and do not believe we have significant amounts of off- balance sheet leases; accordingly we do not expect the adoption of ASU 2016-02 to have a material impact on our consolidated financial statements.

In July 2015, the FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory ("ASU 2015-11"). ASU 2015-11 simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with the lower of cost or net realizable value test. Net realizable value is defined as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The new standard will be applied prospectively and is effective for annual reporting periods beginning after December 15, 2016 and interim periods within those annual periods, with early adoption permitted. We do not expect the adoption of ASU 2015-11 to have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers." ASU 2014-09 is a comprehensive revenue recognition standard that will supersede nearly all existing revenue recognition guidance under current U.S. GAAP and replace it with a principle based approach for determining revenue recognition. ASU 2014-09 will require that companies recognize revenue based on the value of transferred goods or services as they occur in the contract. The ASU also will require additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. ASU 2014-09 is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted only in annual reporting periods beginning after December 15, 2016, including interim periods therein. Entities will be able to transition to the standard either retrospectively or as a cumulative-effect adjustment as of the date of adoption. The Company's primary source of revenue is from the sale of coal through both short-term and long-term contracts with utility companies whereby revenue is currently recognized when risk of loss has passed to the customer. Upon adoption of this new standard, the Company believes that the timing of revenue recognition related to our coal sales will remain consistent with our current practice. The Company is currently evaluating other revenue streams to determine the potential impact related to the adoption of the standard, as well as potential disclosures required by the standard. Because we do not anticipate a change in our pattern of revenue recognition, we anticipate that neither method will have a material impact on our consolidated financial statements.

Subsequent Events

We have evaluated all subsequent events through the date the financial statements were issued. No material recognized or non-recognizable subsequent events were identified.

(2) Vectren Fuels Acquisition

On August 29, 2014, we consummated the acquisition of all the common stock of Vectren Fuels, Inc. (VFI) for $311 million, which was accounted for as a business acquisition requiring measurement of acquired assets and assumed liabilities at their estimated fair value in applying purchase accounting. The estimated fair values are based on market participant assumptions.

(3) Asset Impairment Review

In December 2016, the deterioration of the North end of the Carlisle mine, coupled with lower coal prices led us to determine that the Northern end of the Carlisle mine no longer could be safely and profitably mined. Thus, the decision was made to seal off the North end of the mine. Sealing will be completed in the 1st quarter of 2017. We identified specific assets totaling $16.6 million ($15.1 million of property and equipment and $1.5 million of advanced royalties) that were written off in 2016. After the impairment, the Carlisle assets had an aggregate carrying value of $118 million at December 31, 2016. We conducted a review of the Carlisle mine assets and determined that no further impairment charge was necessary. If, in future periods, we reduce our estimate of the future net cash flows attributable to the Carlisle Mine, it may result in additional future impairment of such assets and such charges could be significant. None of our other assets are considered impaired.

(4) Bank Debt

To finance the August 2014 Vectren Fuels acquisition we entered into a credit agreement with PNC Bank as administrative agent for a group of several other banks. On March 18, 2016, we executed an amendment to our credit agreement. The primary purpose of the amendment was to increase liquidity and maintain compliance through the maturity of the agreement in August 2019. The revolver was reduced from $250 million to $200 million and the term loan remains the same. Our debt at December 31, 2016 was $239 million (term-$102 million, revolver-$137 million). In addition, a maximum annual capex of $30 million was included.

Bank fees and other costs incurred in connection with the initial facility and the amendment were $9.1 million, which were deferred and are being amortized over five years. The credit facility is collateralized by substantially all of Sunrise's assets and we are the guarantor.

The amended credit facility increased the maximum leverage ratio (total funded debt/ trailing 12 months EBITDA) from 2.75X to those listed below:

Fiscal Periods Ended/Ending	Ratio
September 30, 2016 through March 31, 2017	4.50 X
June 30, 2017 through March 31, 2018	4.25 X
June 30, 2018 and September 30, 2018	4.00 X
December 31, 2018	3.75 X
March 31, 2019 and June 30, 2019	3.50 X

The credit agreement matures on August 29, 2019, but we have the right to prepay the loan at any time without penalty.

The amended credit facility also changed the fixed charge coverage ratio to the debt service coverage ratio and requires a minimum of 1.25X through the maturity of the credit facility. The amendment defines the debt service coverage as trailing 12 months EBITDA/annual debt service. As of December 31, 2016, we had additional borrowing capacity of $63 million and total liquidity of $82 million.

At December 31, 2016, our maximum leverage ratio was 2.95 and our debt service coverage ratio was 2.11. Therefore, we were in compliance with those two ratios.

The credit agreement also imposes certain other customary restrictions and covenants as well as certain milestones we must meet in order to draw down the full amount. Any non-tax cash distributions from Savoy are required to be applied toward the debt.

The interest rate on the facility ranges from LIBOR plus 2.25% to LIBOR plus 4%, depending on our leverage ratio. We entered into swap agreements to fix the LIBOR component of the interest rate to achieve an effective fixed rate of no greater than 5% on the original term loan balance and on $100 million of the revolver. The revolver swaps step down 10% each quarter commencing March 31, 2016. At December 31, 2016, these two interest rate swaps had an estimated net fair value liability of $.2 million consisting of a long-term asset of $.3 million and a current liability of $.5 million. Such amounts are included in other long-term assets and accounts payable and accrued liabilities, respectively.

At December 31, 2016, we were paying LIBOR at .78% plus 4% for a total interest rate of 4.78%.

New accounting rules for 2016 required that our debt issuance costs be presented as a direct reduction from the related debt rather than as an asset. Our December 31, 2015, our balance sheet was changed to reflect the new rule.

51

Debt less debt issuance cost at December 31, are presented below (in thousands):

	2016	2015
Current debt	$30,625	$26,250
Less debt issuance cost	(1,829)	(1,394)
Net current portion	$28,796	$24,856
Long-term debt	$207,992	$223,220
Less debt issuance cost	(3,048)	(3,718)
Net long-term portion	$204,944	$219,502

Future Maturities (in thousands):	
2017	$30,625
2018	35,000
2019	172,992
Total	$238,617

(5) Income Taxes (in thousands)

Our income tax is different than the expected amount computed using the applicable federal and state statutory income tax rates. The reasons for and effects of such differences for the years ended December 31 are below:

	2016	2015	2014
Expected amount	$2,966	$9,653	$3,745
Change in Indiana rate		(85)	(1,407)
State income taxes, net of federal benefit	(387)	612	186
Percentage depletion	(6,021)	(2,606)	(1,996)
Stock-based compensation	(238)		343
Captive insurance	(418)	(419)	(419)
Other	72	283	30
	$(4,026)	$7,438	$482

The deferred tax assets and liabilities resulting from temporary differences between book and tax basis are comprised of the following at December 31:

	2016	2015

Long-term deferred tax assets:		
Stock-based compensation	$512	$458
Investment in Savoy	1,031	827
Net operating loss	14,908	7,583
Alternative minimum tax credit	4,221	4,388
Other	564	18
Total long-term deferred tax assets	21,236	13,274
Long-term deferred tax liabilities:		
Coal properties	(50,439)	(46,596)
Oil and gas properties	(15,971)	(15,711)
Total long-term deferred tax liabilities	(66,410)	(62,307)
Net deferred tax liability	$(45,174)	$(49,033)

52

Our effective tax rate (ETR) for 2016 was (48)% compared to 27% for 2015 and 4.5% for 2014. The negative ETR in 2016 is due to the combination of the reduction in book income before taxes because of the asset impairment expense and permanent tax benefits of statutory depletion in excess of tax basis in the mining properties, the captive insurance company and stock based compensation. The low ETR for 2014 was due primarily to the reduction in the Indiana state income tax rate. Our ETR differs from the statutory rate due primarily to statutory depletion in excess of tax basis, which is a permanent difference.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions, to determine whether the positions will more likely than not be sustained by the applicable tax authority. Tax positions not deemed to meet the more-likely-than-not threshold are not recorded as a tax benefit or expense in the current year. We identified our federal tax return and our Indiana state tax return as "major" tax jurisdictions. We believe that our income tax filing positions and deduction will be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. While not material, we record any penalties and interest as SG&A. As of the balance sheet date, the tax year ended December 31, 2012 and all subsequent tax years remain subject to examination by the IRS and state taxing authorities.

(6) Stock Compensation Plans

Restricted Stock Units (RSUs)

Non-vested grants at January 1, 2014	164,000
Granted – weighted average share price on grant date was $8.29	1,195,500
Vested – weighted average share price on vesting date was $10.09	(310,000)
Forfeited	(7,500)
Non-vested grants at December 31, 2014	1,042,000
Granted –share price on grant date was $11.52	2,000
Vested – weighted average share price on vesting date was $7.42	(410,500)
Forfeited	(27,000)
Non-vested grants at December 31, 2015	606,500
Granted – weighted average share price on grant date was $6.84	414,000
Vested – weighted average share price on vesting date was $8.72	(271,500)
Forfeited	(16,000)
Non-vested grants at December 31, 2016 [1]	733,000

(1), 497,500 vest in 2017 and 17,000 vest in 2018, and 219,000 vest in 2019

At December 31, 2016, we had 1,146,516 RSUs available for future issuance.

On the vesting dates, the shares that vested had a value of $2.4 million for 2016, $3.0 million for 2015 and $3.1 million for 2014. Under our RSU plan, participants are allowed to relinquish shares to pay for their required statutory income taxes.

The outstanding RSUs have a value of $6.1 million based on the March 8, 2017 closing stock price of $8.32.

For the years ended December 31, 2016, 2015 and 2014 stock based compensation was $ 2.5 million, $3.1 million, and $3.2 million, respectively. For 2017, based on existing RSUs outstanding, stock-based compensation expense is estimated to be $2.7 million.

Stock Bonus Plan

Our stock bonus plan was authorized in late 2009 with 250,000 shares. Currently, we have 86,383 shares available for future issuance.

(7) Employee Benefits

We have no defined benefit pension plans or any post-retirement benefit plans. We offer our employees a 401(k) Plan, where we match 100% of the first 4% that an employee contributes, a bonus plan based on meeting certain production levels and a discretionary Deferred Bonus Plan for certain key employees. We also offer health benefits to all employees and their families. We have 2,393 participants in our employee health plan. The plan does not cover dental, vision, short-term or long-term disability. These coverages are available on a voluntary basis. We bear some of the risk of our employee health plans. Our health claims are capped at $200,000 per person with a maximum annual exposure of $12.5 million not including premiums.

EMPLOYEE BENEFIT PLANS

(in thousands)

	2016	2015	2014
Health benefits, including premiums	$12,672	$13,400	$8,100
401(k) matching	1,458	2,267	815
Deferred bonus plan	588	445	406
Production bonus plan (discontinued September 1, 2014)			373
Total	$14,718	$16,112	$9,694

Our mine employees are also covered by workers' compensation and such costs for 2016, 2015 and 2014 were approximately $2.3 million, $4.6 million and $2.8 million, respectively. Workers' compensation is a no-fault system by which individuals who sustain work related injuries or occupational diseases are compensated. Benefits and coverage are mandated by each state which includes disability ratings, medical claims, rehabilitation services, and death and survivor benefits. Our operations are protected from these perils through insurance policies. Our maximum annual exposure is limited to $1 million per occurrence with a $4 million aggregate deductible. Based on discussions and representations from our insurance carrier, we believe that our reserve for our workers' compensation benefits is adequate. We have a safety conscious workforce and our worker's compensation injuries have been minimal.

(8) Other Long-Term Assets and Other Income

	2016	2015
Long-term assets:		
Advance coal royalties	$9,296	$6,563
Marketable equity securities available for sale, at fair value (restricted)*	2,036	1,763

Other	2,782	3,090
	$14,114	$11,416

*Held by Sunrise Indemnity, Inc., our wholly owned captive insurance company.

	2016	2015	2014
Other income:			
MSHA reimbursements**	$1,753	$	$
Coal storage fees		600	383
Miscellaneous	2,209	1,636	1,366
	$3,962	$2,236	$1,749

**See “MSHA Reimbursements” in the MD&A section for a discussion of these amounts.

(9) Self Insurance

We self-insure our underground mining equipment. Such equipment is allocated among 10 mining units spread out over 18 miles. The historical cost of such equipment is about $248 million.

(10) Net Income per Share

We compute net income per share using the two-class method, which is an allocation formula that determines net income per share for common stock and participating securities, which for us are our outstanding RSUs.

The following table (thousands, except per share amounts) sets forth the computation of net income per share:

	2016	2015	2014
Numerator:			
Net income	$12,510	$20,132	$10,219
Less earnings allocated to RSUs	(305)	(450)	(375)
Net income allocated to common shareholders	$12,205	$19,682	$9,844
Denominator:			
Weighted average number of common shares outstanding	29,260	29,031	28,776
Net income per share:			
Basic and diluted	$0.42	$0.68	$0.34

(11) Fair Value Measurements

We account for certain assets and liabilities at fair value. The hierarchy below lists three levels of fair value based on the extent to which inputs used in measuring fair value are observable in the market. We categorize each of our fair value measurements in one of these three levels based on the lowest level input that is significant to the fair value measurement in its entirety. These levels are:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our marketable securities are Level 1 instruments.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. We have no Level 2 instruments.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our Level 3 instruments are comprised of interest rate swaps. The fair values of our swaps were estimated using discounted cash flow calculations based upon forward interest-rate yield curves. Although we utilize third party broker quotes to assess the reasonableness of our prices and valuation, we do not have sufficient corroborating market evidence to support classifying these liabilities as Level 2.

The purchase price allocation for the acquisition of VFI was determined using Level 3 measurements. Mobile mining equipment was valued via the market approach. Fixed equipment and mine development was valued via the cost approach using direct and indirect (trending) methods. The mineral reserves and ARO were valued via a discounted future cash flow model.

(12) Equity Method Investments

We own a 50% interest in Sunrise Energy, LLC, which owns gas reserves and gathering equipment with plans to develop and operate such reserves. Sunrise Energy also plans to develop and explore for oil, gas and coal-bed methane gas reserves on or near our underground coal reserves.

We own a 30.6% interest in Savoy Energy, L.P., a private company engaged in the oil and gas business primarily in the state of Michigan. Our 45% ownership was decreased to 40.8% on October 1, 2014 due to the exercise of options by Savoy's management.

On November 3, 2016 Lubar Equity Fund, LLC acquired a 25% interest in Savoy for $9.5 million in cash. Accordingly, our ownership interest was reduced from 40.8% to 30.6%. At closing, Savoy made a cash distribution of $4.4 million of which our share was $1.8 million and per our credit agreement was applied to our bank debt. Mr. Lubar, one of our directors, is affiliated with Lubar Equity Fund, LLC.

During 2016, we received two distributions totaling $3.6 million from Savoy. In 2014, we received distributions totaling $8.1 million from Savoy. All but $3.2 million of such distributions were applied to our bank debt as required under our agreement.

Savoy also recorded impairments of $2.0 million and $2.6 million for the years ended December 31, 2016 and 2015, respectively.

(13) Freelandville and Log Creek Purchases

On March 22, 2016, we completed the purchase of the Freelandville coal reserves, advanced royalties, and coal sales agreement for $18.25 million from Triad Mining LLC. These reserves totaled 14.2 million tons of fee and leased coal and will be mined from our Oaktown 1 portal. This purchase also allows Sunrise access to another 1.6 million tons of our own leased reserves that were previously inaccessible. The purchased coal sales agreement totaled 1,435,000 tons (can be adjusted +/- 6,700 tons monthly). The purchase price allocation for the acquisition was as follows (in thousands):

Purchased coal contract	$6,407
Advanced coal royalties	1,690
Mineral rights and leases	10,153
Total	$18,250

On December 12, 2016, we completed a second transaction with Triad, the purchase of their Log Creek coal sales agreement for $4.1 million. The purchased coal sales agreement included 557,000 tons to be delivered in 2016 and 2017.

(14) Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share data)			
2016:				
Revenue	$75,885	$68,564	$ 65,767	$ 71,234
Operating income	13,745	10,987	7,946	8,237
Net income (loss) *	6,162	5,853	4,322	(3,827)
Basic income per common share	$0.21	$0.19	$ 0.14	$ (0.13)
2015:				
Revenue	$98,001	$95,253	$ 82,013	$ 64,853
Operating income	16,459	12,631	10,986	3,549
Net income	7,591	6,853	5,144	544
Basic income per common share	$0.25	$0.23	$ 0.17	$ 0.02

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* See Note 3 related to asset impairment taken in December 2016.

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

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES.

Disclosure Controls

We maintain a system of disclosure controls and procedures that are designed for the purposes of ensuring that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our CEO and CFO as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our CEO and CFO of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective for the purposes discussed above.

Internal Control Over Financial Reporting (ICFR)

Our management, including our CEO and CFO, is responsible for establishing and maintaining adequate ICFR. Our ICFR is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles in the United States. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance of achieving their control objectives. Management evaluated the effectiveness of our ICFR based on the framework in “Internal Control – Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in 2013.

Our management evaluated, with the participation of our CEO and CFO, the effectiveness of our ICFR as of December 31, 2016. Based on that evaluation, our management concluded that our ICFR was effective at December 31, 2016. EKS&H LLLP has audited and reported on our financial statements and our ICFR as of December 31, 2016. Their report is contained in this Form 10-K.

There were no significant changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2016, that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION None.

PART III

The information required for Items 10-14 is hereby incorporated by reference to that certain information in our Proxy Statement to be filed with the SEC during April 2017.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

ITEM 11. EXECUTIVE COMPENSATION

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

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

See Item 8 for an index of our financial statements.

Our exhibit index is as follows:

3.1	Second Restated Articles of Incorporation of Hallador Energy Company effective December 24, 2009. (1)
3.2	By-laws of Hallador Energy Company, effective December 24, 2009 (1)
10.1	Purchase and Sale Agreement dated December 31, 2005 between Hallador Petroleum Company, as Purchaser and Yorktown Energy Partners II, L.P., as Seller relating to the purchase and sale of limited partnership interests in Savoy Energy Limited Partnership (2)
10.2	Letter of Intent dated January 5, 2006 between Hallador Petroleum Company and Sunrise Coal, LLC (3)
10.3	Reimbursement Agreement, dated April 19, 2006, between Hallador Petroleum Company and Sunrise Coal, LLC (5)
10.4	Membership Interest Purchase Agreement dated July 31, 2006 by and between Hallador Petroleum Company and Sunrise Coal, LLC. (6)
10.5	Purchase and Sale Agreement dated effective as of October 5, 2007 between Hallador Petroleum Company, as Purchaser and Savoy Energy Limited Partnership, as Seller (7)
10.6	Hallador Petroleum Company 2008 Restricted Stock Unit Plan. (8)*
10.7	Form of Amended and Restated Purchase and Sale Agreement dated July 24, 2008 to purchase additional minority interest from Sunrise Coal, LLC's minority members (9)
10.8	Amended and Restated Promissory Note dated December 12, 2008, in the principal amount of $13,000,000, issued by Sunrise Coal, LLC in favor of Hallador Petroleum Company (10)
10.9	Form of Purchase and Sale Agreement dated September 16, 2009 (11)
10.10	Form of Subscription Agreement dated September 15, 2009 (11)
10.11	Form of Hallador Petroleum Company Restricted Stock Unit Issuance Agreement. (11)*
10.12	2009 Stock Bonus Plan (12)*
10.14	Stock Purchase Agreement (Vectren Fuels) (13)
10.15	Second Amended Restated Credit Agreement – August 29, 2014 (14)
10.16	First Amendment to the Second Amended and Restated Credit Agreement dated March 18, 2016 (15)
14	Code of Ethics for Senior Financial Officers. (4)*
21.1	List of Subsidiaries (16)
23.1	Consent of EKS&H LLLP (16)
31	SOX 302 Certifications (16)
32	SOX 906 Certification (16)
95	Mine Safety Disclosure (16)
101	Interactive data files. (16)

(1) IBR to Form 8-K dated December 31, 2009.
(2) IBR to Form 8-K dated January 3, 2006.
(3) IBR to Form 8-K dated January 6, 2006.
(4) IBR to the 2005 Form 10-KSB.
(5) IBR to the Form 8-K dated April 25, 2006
(6) IBR to Form 8-K dated August 1, 2006.
(7) IBR to Form 10-KSB dated December 31, 2007.
(8) IBR to March 31, 2007 Form 10-Q.
(9) IBR to Form 8-K dated July 24, 2008.
(10) IBR to Form 8-K dated December 12, 2008.
(11) IBR to Form 8-K dated September 18, 2009.
(12) IBR to Form S-8 dated December 1, 2009.
(13) IBR to Form 8-K dated July 8, 2014
(14) IBR to Form 10-Q dated November 10, 2014
(15) IBR to Form 10-Q dated May 6, 2016
(16) Filed herewith.

*Management Agreements

ITEM 16. Form 10-K Summary.

As this item is optional, no summary is presented.

SIGNATURES

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

	HALLADOR ENERGY COMPANY
Date: March 10, 2017	/s/ LAWRENCE D. MARTIN Lawrence D. Martin, CFO and CAO

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ DAVID HARDIE David Hardie	Director	March 10, 2017
/s/ VICTOR P. STABIO Victor P. Stabio	Chairman	March 10, 2017
/s/ BRYAN LAWRENCE Bryan Lawrence	Director	March 10, 2017
/s/ BRENT BILSLAND Brent Bilsland	President, CEO and Director	March 10, 2017
/s/ JOHN VAN HEUVELEN John Van Heuvelen	Director	March 10, 2017