UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended: **December 31, 2023** OR

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

Commission file number: 001-3473

HALLADOR ENERGY COMPANY
(www.halladorenergy.com)

Colorado	84-1014610
(State of incorporation)	(IRS Employer Identification No.)
1183 East Canvasback Drive, Terre Haute, Indiana	47802
(Address of principal executive offices)	(Zip Code)

Issuer's telephone number: 812.299.2800

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.01 par value per share	HNRG	Nasdaq Capital Market

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities 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 ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

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

☐ Large accelerated filer	☑ Accelerated filer
☐ Non-accelerated filer	☑ Smaller reporting company
	☐ Emerging growth company

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

The aggregate market value of the common stock held by non-affiliates (public float) on June 30, 2023 was $193,711,455, based on the closing price reported that date by the NASDAQ of $8.57 per share.

As of March 8, 2024, we had 34,885,153 shares outstanding. Our Annual Meeting of Shareholders will be held on May 30, 2024, in Terre Haute, IN.

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,” “will,” and 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 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 macroeconomic and market conditions and market volatility, and the impact of such changes and volatility on our financial position;
- fluctuations in weather, gas and electricity commodity costs, inflation and economic conditions impact demand of our customers and our operating results;
- the outcome or escalation of current hostilities in Ukraine and Israel;
- changes in competition in coal or electricity markets and our ability to respond to such changes;
- changes in coal prices, demand, and availability which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties, including our 2022 acquisition of Hoosier Energy’s Merom Generation Station;
- legislation, regulations, and court decisions and interpretations thereof, including those relating to the environment and the release of greenhouse gases, mining, miner health and safety, and health care, as well as those relating to data privacy protection;
- 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 or long-term customer contracts, including renewing customer contracts upon expiration of existing contracts;
- changing global economic conditions or in industries in which our customers operate;
- investors’, suppliers and other counterparties increasing attention to environmental, social, and governance (“ESG”) matters;
- the effect of changes in taxes or tariffs and other trade measures;
- risks relating to inflation and increasing interest rates;
- liquidity constraints, including due to restrictions contained in our indebtedness and those resulting from any future unavailability of financing;
- customer bankruptcies, a decline in customer creditworthiness, or customer 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 and customer agreements;
- our productivity levels and margins earned on our coal or electricity sales;
- changes in equipment, raw material, service or labor costs or availability, including due to inflationary pressures;
- 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 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 or other accidents, mine fires, mine floods or other interruptions, including unanticipated operating conditions and other events that are not within our control;
- results of litigation, including claims not yet asserted;
- difficulty maintaining our surety bonds for mine reclamation;
- decline in or change in 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;
- risks resulting from climate change or natural disasters;
- difficulty in making accurate assumptions and projections regarding post-mine reclamation;
- uncertainties in estimating and replacing our coal reserves;
- the impact of current and potential changes to federal or state tax rules and regulations, including a loss or reduction of benefits from certain tax deductions and credits;
- difficulty obtaining commercial property insurance;

- evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with equity investments in companies we do not control;
- the severity, magnitude and duration of any future pandemics, including impacts of the pandemic and of businesses' and governments' responses to the pandemic on our operations and personnel, and on demand for coal, the financial condition of our customers and suppliers, available liquidity and capital sources and broader economic disruptions; and
- other factors, including those discussed in "Item 1A. Risk Factors".

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, unless required by law.

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. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of our business.

Regulation and Laws

The coal mining and electric power generation industries are 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 and greenhouse gas emissions;
- water quality standards;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws or that, if spilled, could reach waterways, wetlands, or groundwater;
- plant and wildlife protection, and historic and archeological site and cultural resource protection, that could limit or prohibit mining, exploration, or electric power generation;
- restricting the types, quantities, and concentration of materials that can be released into the environment in the performance of mining, exploration, production, or electric power generation activities;
- discharge of materials;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and
- the effects, if any, that mining or electric power generation activities, including coal combustion residuals, have on groundwater quality and availability.

Failure to comply with environmental laws and regulations may result in the assessment of administrative, civil and criminal sanctions, including monetary penalties, the imposition of strict, joint and several liability, investigatory and remedial obligations, capital expenditures, interruptions, changes in operations, and the issuance of injunctions limiting or prohibiting some or all of the operations on our properties. The regulatory burden on fossil fuel industries increases the cost of doing business and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly obligations could increase our costs and adversely affect our performance. In addition, the electric power industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which has also 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 or electric power generating 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 and electric power generating operations in compliance with applicable federal, state, and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, including 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 or electric power generating 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 as well as the cost of electric power generation.

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, mine closings, and power plant closing, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations, mine closing and power plant closing costs are based upon permit requirements and the estimated 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 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.

Electric Power Generation Permits and Approvals

Numerous governmental permits or approvals are also required for electric power generation operations, including coal-fired power plants such as Merom Generating Station. Applications for permits require extensive engineering and data analysis and presentation and must address a variety of environmental, health, and safety matters associated with electric power generation. These matters include air emissions, the management and disposal of coal combustion residuals and other wastes or materials, and wastewater effluent treatment and discharge, among others. Meeting all requirements imposed to address these matters may be costly and may delay or prevent commencement or continuation of power generation operations.

The permitting process for electric power generation operations can extend over many years as a result of necessary permit renewals and those permitting decisions can be subject to administrative and judicial challenge, including by the public. We cannot assure you that we will not experience difficulty or delays in obtaining electric power generation permits in the future or that a current permit will not be revoked.

We are required to post bonds to secure performance under our coal combustion residuals landfill permit. Under some circumstances, substantial fines and penalties, including revocation of electric power generating permits, may be imposed under the laws and regulations described above and below. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Although, like other power generating 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

The Federal Mine Safety and Health Act of 1977 (“FMSHA”) and regulations adopted pursuant thereto, imposes 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 United States (the “U.S.”) for the 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.

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 the imposition of a civil penalty for each cited violation. Negligence and gravity assessments, along with 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. 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 Miners’ Exposure to Respirable Coal Mine Dust, Including Continuous Personal Dust Monitors.” The final rule implemented 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. MSHA published a request for information regarding engineering controls and best practices to lower miners’ exposure to respirable coal mine dust, and the comment period closed in July 2022. It is uncertain whether MSHA will present additional proposed rules, or revisions to the final rule, following the closing of the comment period.

MSHA has also published, and may continue to publish, various proposed rules or requests for information, which may result in additional rulemakings. For example, in June 2016, MSHA published a request for information on Exposure of Underground Miners to Diesel Exhaust. Following a comment period that closed in November 2016, MSHA received requests for MSHA and the National Institute for Occupational Safety and Health to hold a Diesel Exhaust Partnership to address the issues covered by MSHA's request for information. The comment period for the request for information closed in September 2020.

In August 2019, MSHA published a request for information regarding exposure to respirable crystalline silica, most commonly found in the mining environment through quartz. The request solicited information regarding best practices to protect miners’ health from exposure to quartz, including examination of a new reduced permissible exposure limit, potential new or developing protective technologies, and/or technical and educational assistance. The comment period for the request for information closed in October 2019.

In November 2020, MSHA published a proposed rule to revise Testing, Evaluation, and Approval of Electric Motor-Driven Mine Equipment and Accessories within underground mining environments. The comment period for the proposed rule closed in December 2020.

In September 2021, MSHA published a proposed rule requiring that mine operators employing six or more miners develop and implement a written safety program for mobile and powered haulage equipment at surface mines and surface areas of underground mines (Safety Program for Surface Mobile Equipment). The comment period for the proposed rule closed in November 2021. However, MHSA reopened the rulemaking record for additional public comments. A virtual hearing was held in January 2022, and the comment period closed in February 2022.

It is uncertain whether MSHA will present a final rule addressing any of the above issues or any of the other various proposed rules or requests for information or whether any such rule would have material impacts on our operations or our costs of operation.

Subsequent to the 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 federal and state 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, to some survivors of a miner who dies from this disease, and to a trust fund for the payment of benefits and medical expenses where no responsible coal mine operator has been identified for claims. As of January 1, 2022, the trust fund was funded by an excise tax on production of up to $0.50 per ton for underground-mined coal and up to $0.25 per ton for surface-mined coal, but not to exceed 2% of the applicable sales price. The Inflation Reduction Act of 2022 raised the excise tax, effective October 1, 2022, up to $1.10 per ton of coal from underground mines and up to $0.55 per ton of coal from surface mines, neither amount to exceed 4.4% of the gross sales price.

Workers' Compensation and Black Lung

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. We generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. In addition, coal mining companies are subject to federal legislation and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal workers' pneumoconiosis or black lung. We also provide for these claims through self-insurance programs. Our actuarial calculations are based on numerous assumptions, including disability incidence, medical costs, mortality, death benefits, dependents, and discount rates.

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.

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 underground mining. Currently, approximately 96% of our production capacity involves underground room and pillar mining (no surface subsidence), and approximately 4% involves surface mining. We do not engage in either mountain top removal or long-wall mining. 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 surface disturbance be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore affected surface areas 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 reclamation fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The fee expired on September 30, 2021, and was reauthorized through September 30, 2034, under the Infrastructure Investment and Jobs Act which was signed on November 15, 2021. The fee, as reauthorized, for surface-mined and underground-mined coal is $0.224 per ton and $0.096 per ton, respectively, through September 30, 2034. 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.

Coal Combustion Residuals

In April 2015, the United States Environmental Protection Agency ("EPA") finalized rules on coal combustion residuals ("CCRs"). The rule established nationally applicable minimum criteria for the disposal of CCRs in new and currently operating landfills and surface impoundments, including location restrictions, design and operating criteria, groundwater monitoring, corrective action and closure requirements, and post-closure care. CCRs are generated at Merom Station and the facility is subject to the CCR rule. The EPA has indicated that it will implement a phased approach to amending the CCR Rule, which is ongoing. The CCR rule, current or proposed amendments to the federal CCR rule or state CCR regulations, the results of groundwater monitoring data, or the outcome of CCR-related litigation could have a material impact on our business, financial condition and results of operations.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, for closure and post-closure landfill care, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for our competitors and us to secure new surety bonds without posting collateral, and in some cases, it is unclear what level of collateral will be required. 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 federal and state laws would have a material adverse effect on our ability to produce coal and conduct electric power generating operations, which could affect our profitability and cash flow.

Air Emissions

The Clean Air Act ("CAA") and similar state and local laws and regulations regulate emissions into the air and affect coal mining and electric power generation operations. The CAA directly impacts our coal mining and processing and electric power generation 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 federal and state laws and regulations related to air emissions will make it more costly 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 fossil fuels a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in fossil fuels' share of power generating capacity could have a material adverse effect on our business, financial condition, and results of operations.

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 power 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 electric 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. CSAPR has become increasingly irrelevant with continuing coal plant retirements making the nitrogen oxide ozone budget less stringent and lowering emission allowance prices to levels closer to average operating cost for many of our customers. The full impact of CSAPR is unknown at the present time due to the implementation of Mercury and Air Toxic Standards (“MATS”), discussed below, and the impact of the continuing coal plant retirements.

- 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. In subsequent litigation, the U.S. Supreme Court struck down the MATS rule based on the EPA’s failure to take costs into consideration. The U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. Circuit Court”) allowed the current rule to stay in place until the EPA issued a new finding. In April 2016, the EPA issued a final supplemental finding upholding the rule and concluding that a cost analysis supports the MATS rule. In April 2017, the D.C. Circuit Court of Appeals granted the EPA’s request to cancel oral arguments and ordered the case held in abeyance for an EPA review of the supplemental finding. In December 2018, the EPA issued a proposed Supplemental Cost Finding, as well as the CAA required “risk and technology review.” In May 2020, EPA issued a final rule that reverses the Agency's prior determination from 2000 and 2016 that it was “appropriate and necessary” to regulate hazardous air pollutants (“HAP”) from coal-fueled Electric Generating Units (“EGUs”) under the MATS rule. However, in March 2023, EPA published a final rule revoking the May 2020 finding. The MATS rule has forced electric power 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.

- 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. In March 2019, the EPA published a final rule that retained the current primary NAAQS for sulfur oxide. In December 2020, EPA published a final rule to retain the current NAAQS for both PM and ozone; however, various entities have filed litigation against one or both of these rulemakings, and the Biden Administration announced that it would reconsider and potentially revise the NAAQS. On February 7, 2024, the EPA issued a new final rule regarding the Reconsideration of the NAAQS for PM, and as part of that rule, EPA revised the level of the primary (health-based) annual PM2.5 standard from 12.0 to 9.0 micrograms per cubic meter. With respect to ozone, in August 2023, EPA announced that it is also conducting a new review of the ozone NAAQS. 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 electric power generating operations and 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 or electricity from coal-fired power plants.

- 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-fired power plants. In prior cases, the EPA has decided to negate the SIPs and impose stringent requirements through Federal Implementation Plans (“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. In September 2018, the EPA issued a memorandum that detailed plans to assist states as they develop their SIPs, which was followed by a supplemental memorandum in July 2021 for SIPs for the second implementation period.

- 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 been settled, but others remain pending. In October 2020, the EPA finalized a rule to clarify the process for evaluating whether the NSR permitting program would apply to a proposed modification of a source of air emissions. The EPA has announced that it will review the NSR program. Depending on the ultimate resolution of the EPA's litigation and review, demand for coal could be affected as well as the process by which EPA evaluates modifications to power plants that trigger NSR.

GHG Emissions

Combustion of fossil fuels, such as the coal we produce and the coal that is used at Merom Station, results in the emission of GHGs, such as carbon dioxide and methane. 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. Although no comprehensive climate change regulation has been adopted at the federal level in the U.S., President Biden has announced that climate change will be a focus of his administration. For example, in January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil-fuel industry, a doubling of electricity generated by offshore wind by 2030, and increased emphasis on climate-related risks across governmental agencies and economic sectors. Internationally, the Paris Agreement requires member states to submit non-binding, individually-determined emissions reduction targets. These commitments could further reduce demand and prices for fossil fuels. Although the U.S. had withdrawn from the Paris Agreement, President Biden recommitted the U.S. in February 2021 and, in April 2021, announced a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. The international community gathered again in Glasgow in November 2021 at the 26th Conference to the Parties (""COP26")" during which multiple announcements were made, including a call for parties to eliminate fossil fuel subsidies, among other measures.

Relatedly, the U.S. and European Union jointly announced at COP26 the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. Also at COP26, more than forty countries pledged to phase out coal, although the U.S. did not sign the pledge. At COP27, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase out of inefficient fossil fuel subsidies. The U.S. also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Although no firm commitment or timeline to phase out or phase down all fossil fuels was made at COP27, there can be no guarantees that countries will not seek to implement such a phase out in the future. The impact of these actions remains unclear at this time. Moreover, 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. Others have announced their intent to increase the use of renewable energy sources, displacing coal and other fossil fuels. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal and electricity from coal-fired power plants, such as Merom Station, 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 that the EPA has authority to regulate GHG emissions. Although the U.S. Supreme Court's holding did not expressly involve the EPA's authority to regulate GHG emissions from stationary sources, such as coal-fired power plants, the EPA has determined on its own that it has the authority to regulate GHG emissions from power plants and issued a final rule which found that GHG emissions, including carbon dioxide and methane, endanger both the public health and welfare.

Several rulemakings have been issued under the EPA's New Source Performance Standards ("NSPS") that constrain the GHG emissions of fossil-fuel-fired power plants. In August 2015, the EPA issued its final Clean Power Plan ("CPP") rules that establish carbon pollution standards for power plants, called CO2 emission performance rates. Judicial challenges led the U.S. Supreme Court to grant a stay in February 2016 of the implementation of the CPP before the United States Court of Appeals for the District of Columbia ("Circuit Court") even issued a decision. Then, in October 2017 the EPA proposed to repeal the CPP. The EPA subsequently proposed the Affordable Clean Energy ("ACE") rule to replace the CPP with a rule that utilizes heat rate improvement measures as the "best system of emission reduction." The ACE rule adopts new implementing regulations under the CAA to clarify the roles of the EPA and the states, including an extension of the deadline for state plans and EPA approvals; and the rule revises the NSR permitting program to provide EGUs the opportunity to make efficiency improvements without triggering NSR permit requirements. In June 2019, the EPA published the final repeal of the CPP and promulgation of the ACE rule. On January 19, 2021, the Circuit Court struck down the ACE rule and found the EPA's "repeal of the CPP rested critically on a mistaken reading of the

CAA." On June 30, 2022, the Supreme Court of the United States reversed and remanded the Circuit Court's decision in *West Virginia v. EPA* and found that, in the promulgation of the CPP, the EPA had acted outside the bounds of the legal authority granted to the agency by Congress.

In January 2021, the EPA published a final significant contribution finding for purposes of regulating source category of GHG emissions, confirming that such power plants are a source category for such regulations. However, this finding also excludes several sectors and may, therefore, be subject to revision, and future implementation of the NSPS is uncertain at this time. The EPA published a notice of proposed rulemaking in May 2023 to regulate GHG emissions from new and existing fossil fuel-fired power plants. The rule would require power plants to employ measures to lower GHG emissions, including technologies to capture and sequester their GHG emissions or co-fire with low-GHG hydrogen. EPA has indicated that it expects to finalize the rule in June 2024. Once finalized, the rule is expected to face significant legal, political and technological challenges. The rule could potentially have a material adverse effect on our business, financial condition, and results of operations.

Notwithstanding the ACE rule, the CPP's requirements and impact during the pendency of the litigation led to premature retirements, and the new GHG regulations proposed in May 2023 could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has not currently adopted legislation to restrict carbon dioxide emissions from existing power plants and has not otherwise expanded the legal authority of the EPA following *West Virginia v. EPA*, including as it relates to authority to regulate carbon dioxide emissions from existing and modified power plants as proposed in the NSPS and CPP. We cannot predict whether such legislation will be signed into law in the future.

There have been numerous protests and challenges to the permitting of new fossil fuel infrastructure, including coal-fired power plants and pipelines, 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. Several states have announced their intent to have renewable energy comprise 100% of their electric generation portfolio. Other states may adopt similar requirements, and federal legislation is a possibility in this area. In December 2021, President Biden issued an executive order setting a goal for a carbon pollution-free electricity sector across the country by 2035. To the extent these requirements affect our current and prospective customers, they may reduce the demand for fossil fuel energy, and may affect long-term demand for our coal. Finally, while the U.S. Supreme Court has held that federal common law provides no basis for public nuisance claims against utilities due to their carbon dioxide emissions, the Court did not 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 April 2022, the Council on Environmental Quality ("CEQ") issued a final rule revoking some of the modifications made to the NEPA regulations under the previous administration and reincorporated the consideration of direct, indirect and cumulative effects of major federal actions, including GHG emissions. And, in January 2023, the CEQ released guidance, effective immediately, to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under NEPA.

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 power generating facilities. For example, in 2005, ten Northeastern states entered into the Regional Greenhouse Gas Initiative agreement ("RGGI"), calling for the 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. Since its inception, several additional states and Canadian provinces have joined RGGI as participants or observers, while Virginia has withdrawn from RGGI via executive order by its governor. Similar to RGGI, five western states launched the Western Regional Climate Initiative, although only California and certain Canadian provinces are currently active participants. We cannot predict what other regional greenhouse gas reduction initiatives may arise in the future.

It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with fossil fuel 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 fossil fuel 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. Finally, activists may try to hamper fossil fuel companies by other means, including pressuring financing and other institutions into restricting access to capital, bonding and insurance, as well as pursuing tort litigation for various alleged climate-related impacts.

Water Discharge

The Federal Clean Water Act ("CWA") and similar state and local laws and regulations regulate discharges into certain waters, primarily through permitting. Section 402 of the CWA governs discharges of pollutants into waters of the United States, primarily through National Pollutant Discharge Elimination System ("NPDES") permits. Hallador's Merom Generating Station is subject to an NPDES permit for its wastewater discharges.

Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of certain wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect electric power generation operations and coal mining operations that impact such wetlands and streams. 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. The definition of "waters of the United States," which governs federal jurisdiction under the Clean Water Act, has been subject to many shifting regulations and litigation in recent years. However, in May 2023, the U.S. Supreme Court issued its decision in *Sackett v. EPA*, which significantly limited the scope of federal jurisdiction over wetlands under the Clean Water Act. In response to the Supreme Court's decision, in August 2023, EPA issued its final rule amending the definition of "waters of the United States" to conform its regulations to the Supreme Court's decision in *Sackett*. While the *Sackett* decision and the subsequent rule issued by EPA have reduced the scope of federal regulation at this time, it is possible that more stringent permitting requirements may be imposed in the future, and we are not able to accurately predict the impact, if any, of such permitting requirements.

In order for us to conduct certain activities, we may need to obtain a permit for the discharge of fill material from the U.S. Army Corps of Engineers ("Corps of Engineers") and/or a discharge permit from the state regulatory authority under the state counterpart to the CWA. 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.

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 which veto was subsequently upheld by the D.C. Circuit Court in 2013. Any future use of the EPA's Section 404 "veto" power could create uncertainty 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 revenues. 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 a 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 waterbody 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 or electric power generating operations could require more costly water treatment and could adversely affect our coal production or electric power generation operations.

On November 3, 2015, the EPA published the final Effluent Limitations Guidelines and Standards ("ELG") rule, 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 rule 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. In November 2019, the EPA proposed revisions to the 2015 ELG rule and announced proposed changes to regulations for the disposal of coal ash in order to reduce compliance costs. In October 2020, the EPA published a final rule. In August 2021, the EPA initiated supplemental rulemaking indicating that it intended to strengthen certain discharge limits. The EPA issued a proposed rule for public comment in March 2023, which the agency expects to finalize in 2024. It is unclear what impact these regulations will have on the market for our coal products or on our electric power generating operations.

On April 23, 2020, the U.S. Supreme Court issued a decision in the *Hawaii Wildlife Fund v. County of Maui* case related to whether a CWA permit is required when pollutants originate from a point source but are conveyed to navigable waters through a nonpoint source, such as groundwater. The Court held that discharges to groundwater require a permit if the addition of the pollutants through groundwater is the functional equivalent of a direct discharge from the point source into navigable waters. A number of legal cases relevant to determination of "functional equivalent" are ongoing in various jurisdictions. It is too early to determine whether the Supreme Court decision or the result of litigation to "functional equivalent" may have a material impact on our business, financial condition, or results of operations.

In June 2016, the EPA published the final national chronic aquatic life criterion for the pollutant selenium in fresh water. NPDES permits may be updated to include selenium water quality-based effluent limits based on a site-specific evaluation process, which includes determining if there is a reasonable potential to exceed the revised final selenium water quality standards for the specific receiving water body utilizing actual and/or project discharge information for the generating facilities. As a result, it is not yet possible to predict the total impacts of this final rule at this time, including any challenges to such final rule and the outcome of any such challenges.

The Merom Generating Station is subject to the CWA Section 316(b) rule issued by the EPA effective in 2014 that seeks to protect fish and other aquatic organisms drawn into cooling water systems at power plants and other facilities. These standards require affected facilities to choose among seven BTA options to reduce fish impingement. In addition, certain facilities must conduct studies to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. It is possible that this process, which includes permitting and public input, could result in the need to install closed-cycle cooling systems (closed-cycle cooling towers), or other technology, although the Indiana Department of Environmental Management has previously determined that the systems in place currently at Merom Station meet the BTA requirements. If additional capital expenditures became necessary in the future, they could be material.

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 liability under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations and electric power generating operations generate waste containing hazardous substances. We are currently unaware of any material liability under CERCLA or analogous state laws associated with the release or disposal of hazardous substances from our past or present mine sites or electric power generating operations.

The Federal Resource Conservation and Recovery Act ("RCRA") and analogous state laws impose requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Many mining wastes as well as CCR generated from our electric power generating operations 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.

RCRA impacts the coal industry and electric power generation industry in particular because it regulates the management and disposal of certain coal combustion residuals ("CCR"). On April 17, 2015, the EPA finalized regulations under RCRA for the management and disposal of CCR. Under the finalized regulations, CCR is regulated as "non-hazardous" waste and avoids the stricter, more costly, regulations under RCRA's hazardous waste rules. While classification of CCR as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers' operating costs and potentially reduce their ability to purchase coal as well as increase the operating cost of our electric power generation operations. The CCR rule was subject to legal challenge and ultimately remanded to the EPA. On August 28, 2020, the EPA published a final revised rule mandating closure of unlined impoundments, with deadlines to initiate closure between 2021 and 2028, depending on site specific circumstances. Certain provisions of the revised CCR rule were vacated by the D.C. Circuit Court in 2018. The EPA published a proposed rule in May 2023 that would regulate inactive surface impoundments at inactive electric utilities, called "legacy CCR surface impoundments." Meanwhile, on January 25, 2022, the EPA published determinations for 9 of 57 CCR facilities who sought approval to continue disposal of CCR and non-CCR waste streams until 2023, as opposed to the initial 2021 deadline for unlined impoundments prescribed by the current rule. While the EPA issued one conditional approval, the EPA is requiring the remaining facilities to cease receipt of waste within 135 days of completion of public comment or around July 2022. And, in January 2023, the EPA issued six proposed determinations to deny facilities' requests to continue disposal into unlined surface impoundments. The current determinations, future determinations of the same nature, or similar actions in expected future rulemakings could lead to accelerated, abrupt, or unplanned suspension of coal-fired boilers. The combined effect of the CCR rules and ELG regulations (discussed above) has compelled power generating companies to close existing ash ponds and may force the closure of certain existing coal burning power plants that cannot comply with the new standards. Such retirements may adversely affect the demand for our coal, and the CCR rule requirements and any revisions affect our CCR landfill at Merom Generating Station.

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 potential impacts from mining-related activities. In October 2021, the Biden Administration proposed the rollback of new rules promulgated under the Trump Administration and, in June 2022, the USFWS and the National Marine Fisheries Service published a final rule rescinding the 2020 regulatory definition of "habitat."

If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered, or to re-designate a species from threatened to endangered, we could be subject to additional regulatory and permitting requirements, which in turn could increase operating costs or adversely affect our revenues.

Other Environmental, Health and Safety Regulation

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 regulations. 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.

Climate Change Issues

Physical Climate Risks. Increased frequency of severe and extreme weather events associated with climate change could materially impact our facilities, energy sales, and results of operations. We are unable to predict these events. However, we perform ongoing assessments of physical risk, including physical climate risk, to our business. More extreme and volatile temperatures, increased storm intensity and flooding, and more volatile precipitation leading to changes in lake and river levels are among the weather events that are most likely to impact our business.

Transition Climate Risks. Future legislative and regulatory programs, at both the federal and state levels, could significantly limit allowed GHG emissions or impose a cost or tax on GHG emissions. Revised or additional future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows.

Regarding federal policies, we continue to monitor the implementation of any final and proposed climate change-related legislation and regulations, including the Infrastructure Investment and Jobs Act, signed into law in November 2021; the development of the Enhancement and Standardization of Climate-Related Disclosures, proposed by the SEC in March 2022; the Inflation Reduction Act ("IRA"), signed into law in August 2022; and the EPA's proposed methane regulations for the oil and natural gas industry, but we cannot predict their impact on our business at this time. We have identified potential opportunities associated with the Infrastructure Investment and Jobs Act and the IRA and are evaluating how they may align with our strategy going forward. The energy-related provisions of the Infrastructure Investment and Jobs Act include new federal funding for power grid infrastructure and resiliency investments, new and existing energy efficiency and weatherization programs, electric vehicle infrastructure for public chargers and additional Low Income Home Energy Assistance Program funding over the next five years. The IRA contains climate and energy provisions, including funding to decarbonize the electric sector.

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 principal 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. CAA, 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 re-opened 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 ILB, Central Appalachia ("CAPP"), Northern Appalachia ("NAPP"), 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 PRB is located in northeastern Wyoming and southeastern Montana. The WB includes western Colorado, eastern Utah, and southern Wyoming. Hallador Energy Company ("Hallador"), through its wholly-owned subsidiary Sunrise Coal, LLC ("Sunrise Coal"), mines coal exclusively in the ILB.

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 utilize the continuous mining 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 U.S. 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: BTU), Alliance Resource Partners (Nasdaq: ARLP), and other private producers.

Human Capital

As of December 31, 2023, Hallador and its subsidiaries employed 936 full-time employees and temporary miners, 886 of those employees and temporary miners are directly involved in the coal mining or coal washing process. Our coal workforce is entirely union-free. At our power plant, our operator, Consolidated Asset Management Services (CAMS) employs represented workers. While these workers are not Hallador Power employees, labor disruptions within the CAMS workforce could disrupt our operations at the plant. To attract and retain top talent, we provide competitive wages, an annual bonus for all employees, excellent benefits, an employee health clinic and a culture that is committed to health and safety at all levels.

Employee health and safety is a top priority at Hallador's wholly owned subsidiary, Sunrise Coal. With a robust safety department and safety standards that exceed mandated guidelines, we make safety the foundation of everything we do. While every precaution is taken to prevent mine emergencies, Sunrise Coal has its own private mine rescue team. This team is trained and ready to manage emergency situations at a Sunrise Coal facility, but also ready and available to assist other mine rescue teams. We continuously monitor safety data such as injury severity, violations per inspection day, and significant and substantial citations and compare to the national averages noting that in 2021 we were at or below the national averages in all three categories. For more information about citations or orders for violations of standards under the FMSHA, as amended by the Miner Act, please see our Exhibit 95 to this Annual Report on Form 10-K.

While other companies have moved to high deductible health plans, Hallador is committed to providing comprehensive affordable health insurance with low-cost deductibles and co-pays to take care of our employees and their families. We believe in decreasing the barriers to healthcare, so employees and their dependents do not have to delay care. Our employees and their families also have access to a private full-time health and wellness clinic, with free medications, no cost diagnostics, and a wellness coach.

Beyond investing in the safety and health of its employees, Hallador invests in educational opportunities for its employees. All continuing education requirements and training are completely paid for by the company and tuition reimbursement programs are available to every employee companywide.

Other

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

Our corporate office, as well as Sunrise Coal and Hallador Power Company, LLC's ("Hallador Power") corporate office, is located at 1183 East Canvasback Drive, Terre Haute, Indiana, 47802. All offices can be reached at 812.299.2800. Terre Haute is approximately 70 miles west of Indianapolis.

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to these reports are available, free of charge, on our website at www.halladorenergy.com under the "Investor Relations" section, as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the SEC at www.sec.gov.

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 could 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. and globally may decline if economic conditions deteriorate, which may negatively impact the revenues, 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.

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 or electric power.

In 2023, a significant portion of our coal, capacity and energy sales were under contracts having a term greater than one year, which we refer to as long-term contracts. These 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 could 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 and power industries, our customers 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 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 coal sales contracts contain provisions that allow for the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to the contract to agree on a new price. 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 could 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 coal 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 our products.

During 2023, we derived 93% of our coal revenue from four third-party customers, each representing at least 10% of our coal sales. If in the future we 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. Our electric operations revenue for the first half of 2023 was generated largely by one customer as required by the terms of the Asset Purchase Agreement for our acquisition of Hoosier Energy's Merom Generation Station ("Merom"). While we have subsequently added additional electric power customers and purchasers of accredited capacity, the loss of one or more of these material customers 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 and electric power 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 revenues will decrease, and we may have to reduce production at our mines until our customer's contractual obligations are honored.

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

None of our employees are represented under collective bargaining agreements. However, all of our workforce 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 could still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

Contractors that we use to provide employees at our power plant may experience work stoppages, slowdowns, lockouts or other labor disputes.

At our power plant, our operator, Consolidated Asset Management Services (CAMS), employs represented workers. While these workers are not Hallador Power employees, work stoppages, slowdowns, lockouts or other labor disputes within the CAMS workforce could adversely affect and disrupt our productivity and operations at the plant.

Our recent acquisition of Merom may not achieve its intended results.

On October 21, 2022, the Company, through its subsidiary Hallador Power, completed its acquisition of the one Gigawatt Merom Generating Station located in Sullivan County, Indiana pursuant to an Asset Purchase Agreement with Hoosier Energy. The Company entered into the Asset Purchase Agreement with the expectation that the acquisition of Merom would result in various benefits, including, among other things, securing future demand for a material portion of the Company's coal production and also providing a path for Merom's possible transition to renewable energy when the coal plant is eventually retired. Achieving the anticipated benefits of the acquisition (including the eventual transition to renewable energy) is subject to a number of uncertainties. Failure to achieve these anticipated benefits could result in lower-than-expected revenues or income generated by the combined businesses and diversion of management's time and energy and could have an adverse effect on the Company's business, financial results and prospects. In addition, in connection with the Asset Purchase Agreement, the Company assumed certain decommissioning costs and environmental responsibilities. In the event these assumed costs and responsibilities exceed the Company's estimates, the Company may incur additional liabilities that could have an adverse effect on the Company's business, financial results and prospects.

The operation and maintenance of the Merom facilities or future investment in the Merom facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

The operation and maintenance of generating facilities involves many risks, including the performance by key contracted suppliers and maintenance providers; increases in the costs for or limited availability of key supplies, labor and services; breakdown or failure of facilities; curtailment of facilities by counterparties; or the impact of unusual, adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency. The Merom facilities contain older generating equipment, which even if maintained in accordance with good engineering practices, may require additional capital expenditures to continue operating at peak efficiency, while additional costs may be required as we eventually transition the Merom facilities to renewable energy. In October 2023, the Merom facilities experienced a transformer failure causing one unit to be offline for the month of October; the failed transformer has since been replaced. We may experience similar failures in the future. We could also be subject to costs associated with any unexpected failure to produce and deliver power, including failure caused by breakdown or forced outage, as well as the repair of damage to facilities due to storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events. Additionally, supply chain shortages or delays on key operating components, including but not limited to, transformers, boiler equipment and chemicals or catalysts could materially and adversely impact our operations and reduce revenues or expose the company to significant cover damages related to longer term contracts.

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. Under our outstanding Form S-3 "universal shelf" registration statement, we have the ability, subject to market conditions, to access the debt and equity capital markets as needed, including through the use of our outstanding "at the market" (ATM) offering program. If we raise additional funds by issuing equity securities under our ATM program or otherwise, our stockholders may experience dilution. At times, 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 debt obligations 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.

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, could 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, 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 could 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.

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

The value of our assets has from time to time been adversely affected by numerous uncertain factors, some of which are beyond our control, including, but not limited to unfavorable changes in the economic environments in which we operate, lower-than-expected coal pricing, technical and geological operating difficulties, an inability to economically extract our coal reserves and unanticipated increases in operating costs. These factors may trigger the recognition of additional impairment charges in the future, which could have a substantial impact on our results of coal operations.

In the future as investments in Merom become more significant, the value of those assets could be adversely affected by numerous uncertain factors, some of which are beyond our control, including, but not limited to unfavorable changes in the economic environments in which we operate, environmental, litigation, weather, and regulatory and/or legal changes. These factors may trigger the recognition of additional impairment charges in the future, which could have a substantial impact on our results of power operations.

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 (consolidated adjusted EBITDA/annual debt service) of 1.25 to 1.00 and (ii) a Maximum Leverage Ratio (consolidated funded debt/trailing twelve months adjusted EBITDA) not to exceed 2.25 to 1.00.

On December 31, 2023, our debt service coverage ratio was 3.30, and our leverage ratio was 1.32. Therefore, we were in compliance with these two ratios.

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

On December 31, 2023, our funded bank debt was $91.5 million, we had outstanding convertible notes totaling $19 million, and held letters of credit totaling $18.6 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; and
- make our results of operations more susceptible to adverse economic or operating conditions.

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

If our financial condition deteriorates, certain credit assurance provisions in our power contracts could require additional collateral.

Certain of our power contracts contain credit assurance provisions tied to our financial condition. Should our financial condition deteriorate, these provisions may require substantial collateral that may have a materially adverse effect on our financial condition.

We could be deemed ineligible for the Paycheck Protection Program ("PPP") loan we received in 2020 upon audit by the United States Small Business Administration ("SBA") upon completion of an SBA audit.

The PPP loan application required us to certify that the current economic uncertainty made the PPP loan request necessary to support our ongoing operations. While we made this certification in good faith after analyzing, among other things, our financial situation and access to alternative forms of capital and believe that we satisfied all eligibility criteria and that our receipt of the PPP loan is consistent with the broad objectives of the Paycheck Protection Program of the CARES Act, the certification described above does not contain any objective criteria and is subject to interpretation. In addition, the SBA has stated that it is unlikely that a public company with substantial market value and access to capital markets will be able to make the required certification in good faith. The lack of clarity regarding loan eligibility under the program resulted in significant media coverage and controversy with respect to public companies applying for and receiving loans. If despite our good faith belief that we satisfied all eligibility requirements for the PPP loan, we are found to have been ineligible to receive the PPP loan or in violation of any of the laws or regulations that apply to us in connection with the PPP loan, including the False Claims Act, we may be subject to penalties, including significant civil, criminal and administrative penalties and could be required to repay the PPP loan. We received forgiveness of the entire $10 million of the PPP loan in July 2021, and as a part of the forgiveness process were required to make certain certifications that remain subject to audit and review by governmental entities and could subject us to significant penalties and liabilities if found to be inaccurate. In addition, our receipt of the PPP loan resulted in adverse publicity, and a review or audit by the SBA or other government entity or claims under the False Claims Act could consume significant financial and management resources. Any of these events could harm our business, results of operations, and financial condition.

Investor and lender focus on ESG matters may negatively impact our business, financial results, and stock price.

Companies across all industries, including companies in the fossil-fuel industry, are facing increased scrutiny from stakeholders related to their ESG practices. Companies that do not adapt or comply with evolving investor or stakeholder expectations and standards or are perceived to have not responded appropriately to ESG issues, regardless of any legal requirement to do so, may suffer reputational damage and the business, financial condition, and stock price of such companies could be materially and adversely affected. Several advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through the investment and voting practices of investment advisers, public pension funds, universities, and other members of the investing community. These activities include increasing attention to and demands for action related to climate change, promoting the use of substitutes to fossil-fuel products, encouraging the divestment of fossil-fuel equities, and pressuring lenders to limit funding to companies engaged in the extraction of fossil-fuel reserves. These activities could increase costs, impact our supply chain, reduce demand for our coal, reduce our profits, increase the potential for investigations and litigation, impair our brand, limit our choices for lenders, insurance providers and business partners, and have negative impacts on our stock price and access to capital markets.

In addition, certain organizations that provide corporate governance and other corporate risk information to investors have developed scores and ratings to evaluate companies and investment funds based upon ESG or "sustainability" metrics. Currently, there are no universal standards for such scores or ratings, but consideration of sustainability evaluations is becoming more broadly accepted by investors. Indeed, many investment funds focus on positive ESG business practices and sustainability scores when making investments, whereas other funds may use certain ESG criteria to "screen" certain sectors, such as coal or fossil fuels more generally, out of their investments. In addition, investors, particularly institutional investors, use these scores to benchmark companies against their peers and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance or sell their interests in the company, particularly if its ESG performance does not improve. Moreover, certain members of the broader investment community may consider a company's sustainability score as a reputational or other factor in making an investment decision. Companies in the energy industry, and in particular those focused on coal, natural gas, or oil extraction, often do not score as well under ESG assessments compared to companies in other industries. Consequently, a low ESG or sustainability score could result in our securities being excluded from the portfolios of certain investment funds and investors, restricting our access to capital to fund our continuing operations and growth opportunities. Additionally, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations.

Public statements with respect to ESG matters, such as emission reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential “greenwashing,” i.e., misleading information or false claims overstating potential ESG benefits. For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. Certain non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG-statements, goals, or standards were misleading, false, or otherwise deceptive. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further ESG-related focus and scrutiny.

A significant portion of the electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs, inflation and economic conditions impact demand of our customers and our operating results.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on “normal” weather, which represents a long-term historical average. Significant variations from normal weather resulting from climate change or other factors could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for electricity, whereby usage declines with increased costs, thus affecting our financial results. Commodity prices have been and may continue to be volatile. Lastly, residential and commercial customers’ usage is sensitive to economic conditions and factors such as recession, inflation, unemployment, consumption and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results.

We face various risks related to pandemics and similar outbreaks, which have had and may continue to have material adverse effects on our business, financial position, results of operations, and/or cash flows.

Since first reported in late 2019, the COVID-19 pandemic has dramatically impacted the global health and economic environment, including millions of confirmed cases, business slowdowns or shutdowns, government challenges, and market volatility of an unprecedented nature. The COVID-19 pandemic and related economic repercussions have created significant volatility, uncertainty, and turmoil in the coal and electric industry driven by widespread government-imposed lockdowns. While most government-imposed shut-downs in the U.S. and abroad have been phased out, there is a possibility that such shut-downs may be reinstated if COVID-19 or another pandemic were to again become an acute, severe risk. This could cause a sustained decrease in demand for our coal and electric power and the failure of our customers to purchase coal or electric power from us that they are obligated to purchase pursuant to existing contracts, which would have a material adverse effect on our operations and financial condition. The various governmental and private responses to the pandemic also led to widespread, global supply chain disruptions. These supply chain disruptions have previously caused and may continue to or again cause some of our suppliers to fail to deliver the quantities of supplies we need or fail to deliver such supplies in a timely manner.

The extent to which COVID-19 or another future pandemic may adversely impact our results of operations, cash flows and financial condition depends on future developments, which are highly uncertain and unpredictable.

Enhanced data privacy and data protection laws and regulations or any non-compliance with such laws and regulations, could adversely affect our business and financial results.

The consumer privacy landscape continues to experience momentum for greater privacy protection and reform at the state and federal level in response to precedents set forth by the General Data Protection Regulation (the “GDPR”) and the California Consumer Privacy Act (the “CCPA”). The development and evolving nature of domestic and international privacy regulation and enforcement could impact and potentially limit how Hallador processes personally identifiable information. Beginning January 1, 2023, California residents have increased access rights (including the right to limit the use and disclosure of sensitive personal information), which are enforced by a new state privacy regulator, resulting in more scrutiny of business practices and disclosures. Additional states including Virginia, Utah, Connecticut, Colorado, and Nevada have similarly adopted enhanced data privacy legislation effective in 2023 and patterned after the standards set forth by CCPA, including broader data access rights, with Virginia going a step further requiring businesses to perform data protection assessments for certain processing activities.

As new laws and regulations are created, requiring businesses to implement processes to enable customer access to their data and enhanced data protection and management standards, we cannot forecast the impact that they may have on the Company’s business. Any non-compliance with laws may result in proceedings or actions against the Company by 35 governmental entities or individuals. Moreover, any inquiries or investigations, government penalties or sanctions, or civil actions by individuals may be costly to comply with, resulting in negative publicity, increased operating costs, significant management time and attention, and may lead to remedies that harm the business, including fines, demands or orders that existing business practices be modified or terminated.

The Company's trading and hedging activities do not cover certain risks and may expose it to earnings volatility and other risks.

The Company's trading and hedging activities do not cover certain risks and may expose it to earnings volatility and other risks. In addition to overall price volatility, the Company is currently subject to price volatility on diesel fuel and other commodities utilized in its operations. The Company has entered into certain hedging arrangements to address these risks and may continue in the future to enter into hedging arrangements, including economic hedging arrangements, to manage these risks or other exposures. Since the Company's existing hedging arrangements do not receive cash flow hedge accounting treatment, all changes in fair value are reflected in current earnings.

Some of these hedging arrangements may require the Company to post margin based on the value of the related instruments and other credit factors. If the fair value of its hedge portfolio moves significantly, or if laws, regulations, or exchange rules are passed requiring all hedge arrangements to be exchange-traded or exchange-cleared, the Company could be required to post additional margin, which could negatively impact its liquidity.

Risks Related to our Industry

Substantial or extended volatility 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 in our coal operations, or the price we pay for our coal in the case of our electric operations, as well as our ability to improve productivity and control costs. These prices depend upon factors beyond our control, including:

- the supply of and demand for domestic and foreign coal;
- weather conditions and patterns that affect demand for or our ability to produce coal;
- the proximity to and capacity of transportation facilities;
- supply chain and cost of raw materials for coal operations;
- 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;
- overall domestic and global economic conditions;
- the adverse impact of the COVID-19 pandemic due to the reduction in demand;
- international developments impacting supply of coal; and
- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and regulations affecting the coal mining industry and coal-fired power plants, and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits.

Any adverse change in these factors could result in weaker demand and lower prices for our products. With respect to our coal operations, a substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenues to the extent we are not protected by the terms of existing coal supply agreements (although the adverse impact of a decline in coal prices may in some cases be offset by lower coal prices we pay in our electric operations).

Competition within the coal industry could adversely affect our financial results.

In our coal operations, we compete with other coal producers for domestic coal sales in various regions of the U.S. 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 could 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 could impact our ability to retain or attract customers and could adversely impact our revenues and cash from operations. In our electric operations, similar risks apply with respect to our ability to purchase coal on attractive terms relative to other competitors in the market.

Changes in taxes or tariffs and other trade measures could adversely affect our results of operations, financial position and cash flows.

We pay certain taxes and fees related to our operations. Congress or state legislatures may seek to increase these taxes and fees that relate specifically to the coal industry. We cannot predict further developments, and such increases could have a material adverse effect on our results of operations, financial position, and cash flows.

New tariffs and other trade measures could adversely affect our results of operations, financial position and cash flows. In response to the tariffs imposed by the U.S., the European Union, Canada, Mexico and China have imposed tariffs on U.S. goods and services. The new tariffs, along with any additional tariffs or trade restrictions that may be implemented by the U.S. or retaliatory trade measures or tariffs implemented by other countries, could result in reduced economic activity, increased costs in operating our business, reduced demand and changes in purchasing behaviors for thermal coal, limits on trade with the U.S. or other potentially adverse economic outcomes. While tariffs and other retaliatory trade measures imposed by other countries on U.S. goods have not yet had a significant impact on our business or results of operations, we cannot predict further developments, and such existing or future tariffs could have a material adverse effect on our results of operations, financial position and cash flows and could reduce our revenues and cash available for distribution.

Changes in consumption patterns by utilities regarding the use of coal, including plans by utilities to shut down or move away from coal-fired generation, have affected our ability to sell the coal we produce.

The domestic electric utility industry accounts for the vast majority 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 a significant amount of coal-fired electric power generation in the near term, particularly from older, less efficient coal-fired powered generators.

Future environmental regulation of GHG emissions also could accelerate the use by utilities of fuels other than coal. In addition, federal and state mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. Such mandates, combined with other incentives to use renewable energy sources, such as tax credits, could make alternative fuel sources more competitive with coal. Further, far-reaching federal regulations promulgated by the EPA in the last several 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. A decrease in coal consumption by the domestic electric utility industry could adversely affect the demand for or the price of coal, which could negatively impact our results of operations and reduce our cash from operations.

Other factors, such as efficiency improvements associated with technologies powered by electricity have slowed electricity demand growth and could contribute to slower growth in the future. Further decreases in the demand for electricity, such as decreases that could be caused by a worsening of current economic conditions or a prolonged economic recession, could have a material adverse effect on the demand for coal and our business over the long term.

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 could require further emission reductions and associated emission control expenditures. These laws and regulations could affect demand and prices for coal. There is also continuing pressure on federal and state 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 several 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.

Our operations are subject to a series of risks resulting from climate change.

Combustion of fossil fuels, such as the coal we produce, results in the emission of carbon dioxide into the atmosphere. Concerns about the environmental impacts of such emissions have resulted in a series of regulatory, political, litigation, and financial risks for our business. Global climate issues continue to attract public and scientific attention. Most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere could produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods, and other climatic events. Increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions due to fossil fuels.

In the U.S., no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain sources in the U.S., or constrain the emissions of power plants (though such emissions restraints have been subject to challenge.)

Separately, various states and groups of states have adopted or are considering adopting legislation, regulations, or other regulatory initiatives that are focused on such areas as GHG cap-and-trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. Internationally, the Paris Agreement requires member states to submit non-binding, individually-determined emissions reduction targets. These commitments could further reduce demand and prices for fossil fuels. Although the U.S. had withdrawn from the Paris Agreement, following President Biden's executive order in January 2021, the U.S. rejoined the Agreement and, in April 2021, established a goal of reducing economy-wide net GHG emissions 50-52% below levels by 2030. Additionally, at COP26 in Glasgow in November 2021, the U.S. and the European Union jointly announced the launch of a Global Methane Pledge committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. At COP27 in Sharm El-Sheik in November 2022, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase out of inefficient fossil fuel subsidies. The U.S. also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Although no firm commitment or timeline to phase out or phase down all fossil fuels was made at COP27, there can be no guarantees that countries will not seek to implement such a phase out in the future. The full impact of these actions is uncertain at this time and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects upon us and our operators' operations.

Governmental, scientific, and public concern over climate change has also resulted in increased political risks, including certain climate-related pledges made by certain candidates now in political office. In January 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil-fuel industry, a doubling of electricity generated by offshore wind by 2030, and increased emphasis on climate-related risks across governmental agencies and economic sectors. Other actions that may be pursued include restrictive requirements on new pipeline infrastructure or fossil-fuel export facilities or the promulgation of a carbon tax or cap and trade program. Further, although Congress has not passed such legislation, almost half of the states have begun to address GHG emissions, primarily through the planned development of emissions inventories, regional GHG cap and trade programs, or the establishment of renewable energy requirements for utilities. Depending on the particular program, we or our customers could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations. Litigation risks are also increasing.

Additionally, on March 6, 2024, the SEC adopted new rules relating to the disclosure of a range of climate-related data risks and opportunities, including financial impacts, physical and transition risks, related governance and strategy and GHG emissions, for certain public companies. We are currently assessing this rule but at this time we cannot predict the ultimate impact of the rule on our business or those of our customers. As a result of these final rules, we or our customers could incur increased costs related to the assessment and disclosure of climate-related risks and certain emissions metrics. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors.

Apart from governmental regulation, there are also increasing financial risks for fossil-fuel producers as stakeholders of fossil-fuel energy companies may elect in the future to shift some or all of their support into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil-fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil-fuel sector. In late 2020, the Federal Reserve announced it had joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector, and, in September 2022, announced that six of the U.S.’ largest banks will participate in a pilot climate scenario analysis to enhance the ability of firms and supervisors to measure and manage climate-related financial risk. The Federal Reserve released its pilot exercise in January 2023 which is designed to analyze the impact of both physical and transition risks related to climate change on specific assets of the banks’ portfolio. Although we cannot predict the effects of these actions, such limitation of investments in and financing, bonding, and insurance coverages for fossil-fuel energy companies could adversely affect our coal mining operations.

The adoption and implementation of new or more stringent international, federal, or state legislation, regulations, or other regulatory initiatives that impose more stringent standards for GHG emissions from fossil-fuel companies could result in increased costs of compliance or costs of consuming, and thereby reduce demand for coal, which could reduce the profitability of our interests. Additionally, political, litigation, and financial risks could result in either us restricting or canceling mining activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments, as well as concerted conservation and efficiency efforts that result in reduced electricity consumption, and consumer and corporate preferences for non-fossil-fuel sources, including alternative energy sources, could cause prices and sales of our coal to materially decline and could cause our costs to increase and adversely affect our revenues and results of operations.

Climate change may also result in various physical risks, such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns that could adversely impact our operations. Such physical risks may result in damage to our facilities or otherwise adversely impact operations which could decrease our production. We may not have insurance to cover these risks and the consequences for our operations could have a negative impact on the costs and revenues from operations.

We or our customers could be subject to related to the alleged effects of climate change.

Increasing attention to climate change risk has also resulted in a recent trend of governmental investigations and private litigation by state and local governmental agencies as well as private plaintiffs in an effort to hold energy companies accountable for the alleged effects of climate change. Other public nuisance lawsuits have been brought in the past against power, coal, and oil & gas companies alleging that their operations are contributing to climate change. The plaintiffs in these suits sought various remedies, including punitive and compensatory damages and injunctive relief. While the U.S. Supreme Court held that federal common law provided no basis for public nuisance claims against the defendants in those cases, tort-type liabilities remain a possibility and a source of concern. Government entities in other states (including California and New York) have brought similar claims seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the GHG emissions attributable to those fuels. Those lawsuits allege damages as a result of climate change and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Separately, litigation has been brought against certain fossil-fuel companies alleging that they have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or consumers. We have not been made a party to these other suits, but it is possible that we could be included in similar future lawsuits initiated by state and local governments as well as private claimants.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in liabilities to us. In addition, government inspectors, under certain circumstances, have the ability to order our operations to be shut down based on environmental considerations.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as "acid mine drainage." We could become subject to claims for toxic torts, natural resource damages and other damages, as well as for the investigation and clean-up of soil, surface water, groundwater and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or for the entire share. In addition, government inspectors, under certain circumstances, may have the ability to order our operations to be shut down based on a perceived or actual violation of regulations concerning hazardous substances and other matters related to environmental protection.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could adversely affect us.

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

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 could 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 profitability could 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 revenues and profitability, which could materially adversely impact our quarterly or annual results.

Our inability to obtain commercial insurance at acceptable rates or our failure to adequately reserve for self-insured exposures could increase our expenses and have a negative impact on our business.

We believe that commercial insurance coverage is prudent in certain areas of our business for risk management. Insurance costs could increase substantially in the future and could be affected by natural disasters, fear of terrorism, financial irregularities, cybersecurity breaches and other fraud at publicly traded companies, intervention by the government, an increase in the number of claims received by the carriers, and a decrease in the number of insurance carriers. In addition, the carriers with which we hold our policies could go out of business or be otherwise unable to fulfill their contractual obligations or could disagree with our interpretation of the coverage or the amounts owed. In addition, for certain types or levels of risk, such as risks associated with certain natural disasters or terrorist attacks, we may determine that we cannot obtain commercial insurance at acceptable rates, if at all. Therefore, we may choose to forego or limit our purchase of relevant commercial insurance, choosing instead to self-insure one or more types or levels of risks. If we suffer a substantial loss that is not covered by commercial insurance or our self-insurance reserves, the loss and related expenses could harm our business and operating results. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, environmental activists could try to hamper fossil-fuel companies by other means including pressuring insurance and surety companies into restricting access to certain needed coverages.

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 could be costly and time-consuming and could 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 could 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. Federal and state 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 have an adverse effect on our results of operation and financial position.

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.

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.

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.

Inflation could result in higher costs and decreased profitability.

The U.S., European Union and other large economies have recently experienced inflation at a rate significantly higher than recent years. Current and future inflationary effects may be driven by, among other things, governmental stimulus and monetary policies, supply chain disruptions and geopolitical instability, including the ongoing military conflict between Ukraine and Russia. This recent inflation has resulted in rising prices, including increases in freight rates, prices for energy and other costs, and has adversely impacted us and may further impact us negatively in the future. Sustained inflation could result in higher costs for transportation, energy, materials, supplies and labor. Our efforts to recover inflation-based cost increases from our customers may be hampered as a result of the structure of our contracts and competitive pressures. Accordingly, substantial inflation may have an adverse impact on our business, financial position, results of operations and cash flows. Inflation has also resulted in higher interest rates in the U.S., which could increase our cost of debt borrowing in the future.

Increases in interest rates could adversely affect our business.

The Federal Reserve raised the federal funds interest rate throughout December 31, 2023, in its effort to take action against domestic inflation, and rates are expected to remain higher throughout 2024. We have exposure to these past increases in interest rates and may be affected further in the future. Based on our current variable debt level of $91.5 million as of December 31, 2023, comprised of funds drawn on our outstanding bank debt, an increase of one percentage point in the interest rate will result in an increase in annual interest expense of slightly less than $1 million. Any indebtedness we incur in the future may also expose us to increased interest rates, whether as a result of higher fixed rates at the time such a new facility is entered into or because such new indebtedness accrues interest at a variable rate. As a result, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenues 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 could face difficulties in the future that could impair our ability to supply coal to our customers, resulting in decreased revenues. 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.

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 revenues.

Political or financial instability, currency fluctuations, the outbreak of pandemics or other illnesses (such as the COVID- 19 pandemic), labor unrest, transport capacity and costs, port security, weather conditions, natural disasters, or other events that could alter or suspend our operations, slow or disrupt port activities, or affect foreign trade are beyond our control and could materially disrupt our ability to participate in the export market for coal sales, which could adversely affect our sales and our results of operations.

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, including through our recent acquisition of Merom. 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.

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 could adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also could 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 could prove inaccurate and could result in decreased profitability.

The estimates of our coal reserves could vary substantially from actual amounts of coal we are able to recover economically. 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 could 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;
- 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 could change unexpectedly. Our electric operations are also affected by many of these same commodity prices, including chemicals and catalysts necessary to operate the plant in accordance with environmental and other regulations, fuel oil, and raw materials used in the manufacture and maintenance of equipment throughout the plant. Inflationary pressures have and could continue to lead to price increases affecting many of the components of our operating expenses such as fuel, steel, other materials and maintenance expense.

There could 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.

Certain federal income tax deductions currently available with respect to coal mining and production may be eliminated as a result of future legislation.

In past years, members of Congress have indicated a desire to eliminate certain key U.S. federal income tax provisions currently applicable to coal companies, including the percentage depletion allowance with respect to coal properties. Elimination of those provisions would negatively impact our financial statements and results of operations.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs and could adversely affect our profitability.

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least one year of experience and proficiency in multiple mining tasks. In recent years, a shortage of experienced coal miners has caused us to include some inexperienced staff in the operation of certain mining units, which decreases our productivity and increases our costs. This shortage of experienced coal miners is the result of a significant percentage of experienced coal miners reaching retirement age, combined with the difficulty of retaining existing workers in and attracting new workers to the coal industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal, which could adversely affect our profitability.

Disruptions in supply chains could significantly impair our operating profitability.

We are dependent upon vendors to supply mining equipment, equipment within our power plant, safety equipment, supplies, and materials. If a vendor fails to deliver on its commitments, or if common carriers have difficulty providing capacity to meet demands for their services, we could experience reductions in our production or increased production costs, which could lead to reduced profitability and adversely affect our results of operations.

Inflationary pressures could significantly impair our operating profitability.

Any future inflationary or deflationary pressures could adversely affect the results of our operations. For example, at times our results have been significantly impacted by price increases affecting many of the components of our operating expenses such as fuel, steel, maintenance expense and labor. In addition to potential cost increases, inflation could cause a decline in global or regional economic conditions that reduce demand for our coal or electric power and could adversely affect our results of operations.

The Russian-Ukrainian conflict, and sanctions brought against Russia, as well as other disruptions throughout Europe and the Middle East have caused significant market disruptions that may lead to increased volatility in the price of commodities.

The extent and duration of the military conflict involving Russia and Ukraine, resulting sanctions and future market or supply disruptions in the region are impossible to predict, but could be significant and may have a severe adverse effect on the region. Globally, various governments have banned imports from Russia including commodities such as coal. Additionally, the ongoing conflict between Israel and Hamas, as well as the increasing instability throughout the Middle East, could result in additional disruptions in the commodities markets, supply chain and the global economy. These events have caused volatility in the aforementioned commodity markets. Although we have not experienced any material adverse effect on our results of operations, financial condition or cash flows as a result of the war or conflict or the resulting volatility from such events, such volatility, may significantly affect prices for our coal or the cost of supplies and equipment, as well as the prices of competing sources of energy for our electric power plant customers.

These events, along with trade and monetary sanctions, as well as any escalation of the conflicts and future developments, could significantly affect worldwide market prices and demand for our coal and cause turmoil in the capital markets and generally in the global financial system. Additionally, the geopolitical and macroeconomic consequences of these events and associated sanctions cannot be predicted, but could severely impact the world economy. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for products, causing a reduction in our revenues or an increase in our costs and thereby materially and adversely affecting our results of operations.

The integration of any expansions or acquisitions that we complete will be subject to substantial risks.

Even if we make expansions or acquisitions that we believe will increase our revenue, any expansion acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, and operating expenses;
- a decrease in our liquidity by using a significant portion of our cash generated from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;
- an inability to hire, train or retain qualified personnel to manage and operate the acquired assets; and
- the occurrence of other significant changes, such as impairment of properties, goodwill or other intangible assets, asset devaluation, or restructuring charges.

Natural disasters and other events beyond our control could materially adversely affect us.

Natural disasters or other events outside of our control may cause damage or disruption to our operations, and thus could have a negative effect on us. Our business operations are subject to interruption by natural disasters, fire, power shortages, pandemics and other events beyond our control. This may result in delivery delays, malfunctioning of facilities or shutdown of logistic points. Such events could make it difficult or impossible for us to deliver our products and services to our customers and could decrease demand for our services. We could not assure you that the production facilities and logistic points will always operate normally in the future.

ITEM 1B. UNRESOLVED STAFF COMMENTS. None.

ITEM 1C. CYBERSECURITY.

Risk Management and Strategy

We rely on information technology to operate our business. We have endpoint and other protection systems, and incident response processes, both internally and through third-party consultants, designed to protect our information technology systems. These established processes assist us to continuously assess and identify threats to our systems and minimize impact to our business in the event of a breach or other security incident. With our third-party consultants, the processes protect our information systems and allow us to resolve issues timely.

As new threats to security may be identified, our personnel are notified, with instruction to increase awareness of the threat and how to react if such a threat or actual breach appears to be encountered. Periodic educational notices are also disseminated to all personnel. Additionally, as our systems are modified and upgraded, all personnel are notified, with instruction as appropriate. Responsibility for the identification and assessment of risks and the recommendation of upgrades to our systems resides with our expert consultants who report to our IT Director.

Governance

Our Board oversees the risks involved in our operations as part of its general oversight function, integrating risk management into the Company’s compliance policies and procedures. With respect to cybersecurity, the Board has the ultimate oversight responsibility, with the Audit Committee and IT Steering Committee each having certain responsibilities relating to risk management of cybersecurity.

Among other things, the Audit Committee discusses with management the Company’s major policies with respect to risk assessment and risk management, including cyber-security, as they relate to the integrity of the Company’s accounting and financial reporting processes and the Company’s compliance with legal and regulatory requirement.

In addition to its other responsibilities, the IT Steering Committee oversees operational information technology risks, including cybersecurity, as they relate to the technical aspects of the Company's operations.

The IT Steering Committee and/or the full Executive Team receive at least quarterly reports from management on information technology matters, including cybersecurity. The reports address upgrades to hardware, software, and IT systems throughout the Company, and include the identification of IT and cybersecurity risks. Security scores, risk management, and mitigation measures are routinely presented. As discussed above, we maintain endpoint and other protection systems, and incident response processes, both internally and through third-party experts. As these systems, processes, training, and upgrades are implemented, updates are provided to the Executive Team.

We have not identified an indication of a substantive cyber security incident that would have a material impact on our business, results of operations or financial statements. For additional information regarding risks from cybersecurity threats, please refer to Item 1A, "Risk Factors," above.

ITEM 2. PROPERTIES.

See "Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of our mines.

ITEM 3. LEGAL PROCEEDINGS. None

ITEM 4. MINE SAFETY DISCLOSURES:

Safety is a core value for us and our subsidiaries. As such, we have dedicated a great deal of time, energy, and resources to creating a culture of safety.

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 trades on the NASDAQ Capital Market under the symbol HNRG, and 30.5% is held by our officers, directors, and their affiliates.

On March 8, 2024, we had 215 shareholders of record of our common stock; this number does not include the shareholders holding stock in "street name." We estimate we have over 5,000 street name holders.

Equity Compensation Plan Information

See Note 8 to our consolidated financial statements.

ITEM 6. [RESERVED]

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. The following analysis includes a discussion of metrics on a per ton and per mega-watt hour (MWh) basis as derived from the condensed consolidated financial statements, which are considered non-GAAP measurements. These metrics are significant factors in assessing our operating results and profitability.

OVERVIEW

Hallador Energy Company (the "Company" or "Hallador") is an energy company operating in the state of Indiana. Historically, the largest portion of our business has been devoted to coal mining in the State of Indiana through Sunrise Coal, LLC (a wholly-owned subsidiary) serving the electric power generation industry.

On October 21, 2022, the Company, through its wholly owned subsidiary Hallador Power, acquired the Merom Generating Energy Station ("Merom"), a one gigawatt ("GW") power plant located in Sullivan County, Indiana. Merom is located in the Midcontinent Independent System Operator's ("MISO") footprint. We believe this acquisition is the catalyst that began Hallador's transition from a producer of coal to a vertically integrated independent power producer ("IPP").

As a result of the Merom acquisition the Company has two reportable segments: coal operations (operated by Sunrise Coal, LLC) and electric operations (operated by Hallador Power). In addition to our reportable segments, the remainder of our operations are presented as "Corporate and Other" and primarily are comprised of unallocated corporate costs in addition to activities such as a 50% interest in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana, accounted for using the equity method, and our wholly-owned subsidiary Summit Terminal LLC, a logistics transport facility located on the Ohio River.

2023 was the first whole year in which Hallador Power operated Merom. In accordance with the Purchase and Sale Agreement associated with the Merom acquisition, for the first five months of 2023, all fuel consumed at Merom was delivered from a third party and all energy produced was sold at $34 per MWh. Beginning in June 2023, approximately seventy percent of Merom's energy became available to sell on the open market. However, despite spot prices for electricity at Merom averaging $39 in 2021 and $69 in 2022, generally milder weather and depressed natural gas prices drove down the average spot price for electricity to $31 in 2023.

Despite near record margins at our coal division for the full year, the fourth quarter was a particularly challenging quarter for Hallador Power. A failure in Merom's main Generator Step-Up Transformer (GSU) coupled with a scheduled maintenance outage took half of the plant offline for nearly the entire quarter. The planned maintenance resulted in $12.6 million in expenditures and the transformer replacement resulted in an additional $0.7 million in unplanned capital expenditures. Additionally, natural gas prices, which have great influence on overall electricity price, remained low throughout the second half of 2023 and dropped to an inflation adjusted all-time low in the first quarter of 2024.

The acquisition of Merom, brought with it additional capex spending requirements to maintain and return the power plant to top condition, which we expected to pay for with fourth quarter free cash flow from in-quarter power sales. However, with fourth quarter challenges at both Merom and in our coal division, Sunrise Coal, we took steps to protect liquidity and to increase the efficiency of our operations. Thus, in December and early January we improved liquidity and provided operational flexibility through an At-The-Market (ATM) offering. Under the ATM, we sold approximately 800,000 shares of Hallador stock in December 2023 and raised approximately $7.3 million of equity resulting in 34,051,154 shares outstanding at December 31, 2023. Approximately 700,000 shares of Hallador stock was sold in January 2024 raising an additional $6.6 million of equity. Hallador’s share count stands at 34.9 million shares as of March 8, 2024. Liquidity at year end was $26.2 million. Subsequently, in February 2024, we further added to liquidity as several members of Hallador's Board of Directors loaned the company a total of $5 million through an unsecured one year note at an interest rate of 12% per annum. Receipt of roughly $36 million in capacity revenue for the 2024-2025 planning year will begin in the first quarter of 2024, further strengthening our financial position. See Note 4 to our consolidated financial statements for additional discussion about our bank debt and related liquidity.

On February 23, 2024, our Coal Operations Segment undertook an initiative designed to strengthen our financial and operational efficiency and to create significant operational savings and higher margins in our coal segment. This step will advance our transition from a company primarily focused on coal production to a more resilient and diversified vertically integrated IPP. As part of this initiative, we idled production at our higher cost Prosperity Mine, and substantially idled production at Freelandville Mine with minimal production. This should reduce our capital reinvestment for coal production in 2024 by approximately $10 million. We also focused our seven units of underground equipment on four units of our lowest cost production at our Oaktown Mine. As part of the initiative, we reduced our workforce by approximately 110 employees.

Historically, Sunrise Coal has generated approximately six million tons of coal annually. Following the restructuring, we expect Sunrise to produce roughly 4.5 million tons of coal annually at improved margins to our former structure. Additionally, in 2024, we have secured supplemental coal from third party suppliers at favorable prices. This allows us to diversify self-production supply risk and provides us with additional flexibility in our sales portfolio. The optionality to obtain low-cost tons either internally or from third parties while capturing upward swings in the commodities markets for coal should further maximize margins while optimizing fuels costs at Merom.

In addition to the expected improvements in coal margins, Merom has the capability to provide revenue on up to 6 million mega-watt-hours (MWh) annually. Based on the currently available forward power price curves, we believe over time, the margins earned on energy and capacity sales will be more than double our historical margins of approximately eight dollars per ton on coal production. Furthering this belief, in Q3 we reported contracted sales of 3.4 million MWh to be delivered in 2026-2028 at MWh margins that we believe could exceed twenty-five dollars per MWh. We continue to see strong indications for both energy and capacity sales in 2024 and in future years. Our approach has been to sell energy primarily through bi-lateral agreements on a unit contingent basis in an attempt to reduce our exposure to market risk if we fail to produce due to operational issues in what we believe to be an increasingly volatile power market. While we are seeing success in this approach, sales of this type are largely bespoke and require more time and negotiation than a typical firm power sale as we build our forward sales positions. As we methodically work to contract our forward sales book, we continue to sell energy on the spot market, resulting in episodic cash generation largely dependent on demand created by seasonal weather and various other conditions which stress the power grid.

The ability to store a commodity is inherently tied to the volatility of that commodity. Coal can be piled up for years, thus its volatility is low. Oil and gas face transportation and storage challenges which increase price volatility. Batteries and hydro generation are improving, but current technology and expense limit the ability to economic practicability of implementing the technology on a large-scale basis. We believe that the lack of economically viable storage options coupled with the challenges of non-dispatchable generation gaining market share in an environment where the sun does not always shine and the wind does not always blow, indicates that energy’s price volatility is likely to increase over the next decade. This volatility appears to be keeping the forward power price premium intact.

In an effort to capture additional margins above our traditional wholesale energy markets, we recently agreed to a structure with Hoosier Energy and their distribution member, WIN REMC, that should allow us to attract industrial users of power, such as data centers, AI providers and power dense manufacturers, to the Merom property. We believe leveraging our plant to help supply these large users of energy with reliable, resilient electricity should allow us to operate more efficiently in a volatile power environment, generate increased margins and support the fragile power grid as it navigates the challenges of transition to new sources of energy in the coming decades. These types of relationships should allow us to capture the upside of increasing demand and volatility while providing stability to our earnings and ability to dispatch in a world that is consistently seeking more electricity but lacks the real time infrastructure and generation to satisfy those increasing power needs. Combined with our increased volume of forward power sales, we believe that these types of opportunities will continue to improve the outlook for the company and provide a stable platform to leverage both our power and coal assets in a responsible and sustainable manner.

We are excited about the transformation of Hallador from a commodity focused producer of coal to a vertically integrated IPP. We believe that this transition provides significant opportunity to capture the increased margins of the energy markets, to take advantage of the increasing demand for electricity and to step up the value chain in a more sustainable and future proofed industry than that which we have traditionally operated in. As evidenced by the ongoing build of our long-term sales book, our deliberate movement into the electricity sector should materially strengthen our company and the products that we sell.

Solid Forward Sales Position - Segment Basis, Before Intercompany Eliminations

	2024	2025	2026	2027	2028	Total
Coal						
Priced tons - 3rd party (in millions)	3.4	1.8	0.5	0.5	-	6.2
Average price per ton - 3rd party	$ 51.82	$ 50.57	$ 56.09	$ 56.09	$ -	
Priced tons (in millions) - Hallador Power	1.5	2.3	2.3	2.3	2.3	10.7
Average price per ton - Hallador Power	$ 51.00	$ 51.00	$ 51.00	$ 51.00	$ 51.00	
Contracted coal revenue (in millions)	$ 252.69	$ 208.33	$ 145.35	$ 145.35	$ 117.30	$ 869.02
% Priced	109%	91%	62%	62%	51%	
Committed & unpriced tons (in millions) - 3rd party	-	1.0	1.0	1.0	-	3.0
Committed & unpriced tons (in millions) - Hallador Power	-	-	-	-	-	-
Total contracted tons (in millions)	4.9	5.1	3.8	3.8	2.3	19.9
% Coal Sold*	109%	113%	84%	84%	51%	
Average cost per ton of coal sold was $33.67 for the year ended December 31, 2023 ($26.98 after eliminating for intercompany sales to Hallador Power)						
2024 Coal Capex Budget (in millions)	$ 25.00					
Power						
Energy						
Contracted MWh (in millions)	1.87	1.90	1.83	1.78	1.09	8.47
Average contracted price per MWh	$ 35.23	$ 36.06	$ 55.37	$ 54.65	$ 52.98	
Contracted revenue (in millions)	$ 65.88	$ 68.51	$ 101.33	$ 97.28	$ 57.75	$ 390.75
% Energy Sold*	31%	32%	31%	30%	18%	
Capacity						
Average daily contracted capacity	810	748	743	623	454	
% Capacity Contracted**	94%	87%	86%	72%	53%	
Average contracted capacity price per MWd	$ 200	$ 210	$ 230	$ 226	$ 224	
Contracted capacity revenue (in millions)	$ 59.13	$ 57.33	$ 62.37	$ 51.39	$ 37.12	$ 267.34
Total Energy & Capacity Revenue						
Contracted Power Revenue (in millions)	$ 125.01	$ 125.84	$ 163.70	$ 148.67	$ 94.87	$ 658.09
Contracted Power Revenue per MWh*	$ 45.69	$ 47.05	$ 67.40	$ 66.47	$ 64.70	
2023 average cost per MWh sold was $33.67 for the year ended December 31, 2023 ($26.98 assuming intercompany sales of coal were sold at cost)						
2024 Power Capex Budget (in millions)	$ 18.00					
TOTAL CONTRACTED REVENUE (IN MILLIONS)	$ 377.70	$ 334.17	$ 309.05	$ 294.02	$ 212.17	$ 1,527.11

* Based on coal production of 4.5 million tons and 6.0 million MWh annually.

** Based on a MISO accreditation of 860MW per day. Accreditations are adjusted annually based on 3-year rolling performance metrics.

Internal Controls Disclosure

The preparation of coal reserve and resource estimates is conducted by independent individuals who are by virtue of their education, experience and professional association considered qualified persons (as defined in SEC rules). Company personnel meet on an annual basis with the independent qualified person to provide updates to the reserve and resource estimates. Company personnel review the work of the qualified person to ensure such work is prepared in accordance with applicable rules and regulations and that the data and assumptions provided were properly applied to the final reserve and resource model. The Company's engineering personnel ensure estimates are based on current mine plans, incorporate the most recent drilling and lab data, properly reflect changes in permitting status, consider known encumbrances, and are consistent with operating knowledge and expectations in terms of mining methods, recovery rates, minimum seam heights or maximum strip ratios, and saleable qualities.

An American National Standards Institute-certified third-party laboratory is utilized to support reserve and resource estimates. The laboratory follows standard sample preparation, security, and environmental procedures. In addition, the Company's qualified person performs independent data verification procedures to ensure data is of sufficient quantity and reliability to reasonably support the coal reserve and resource estimates.

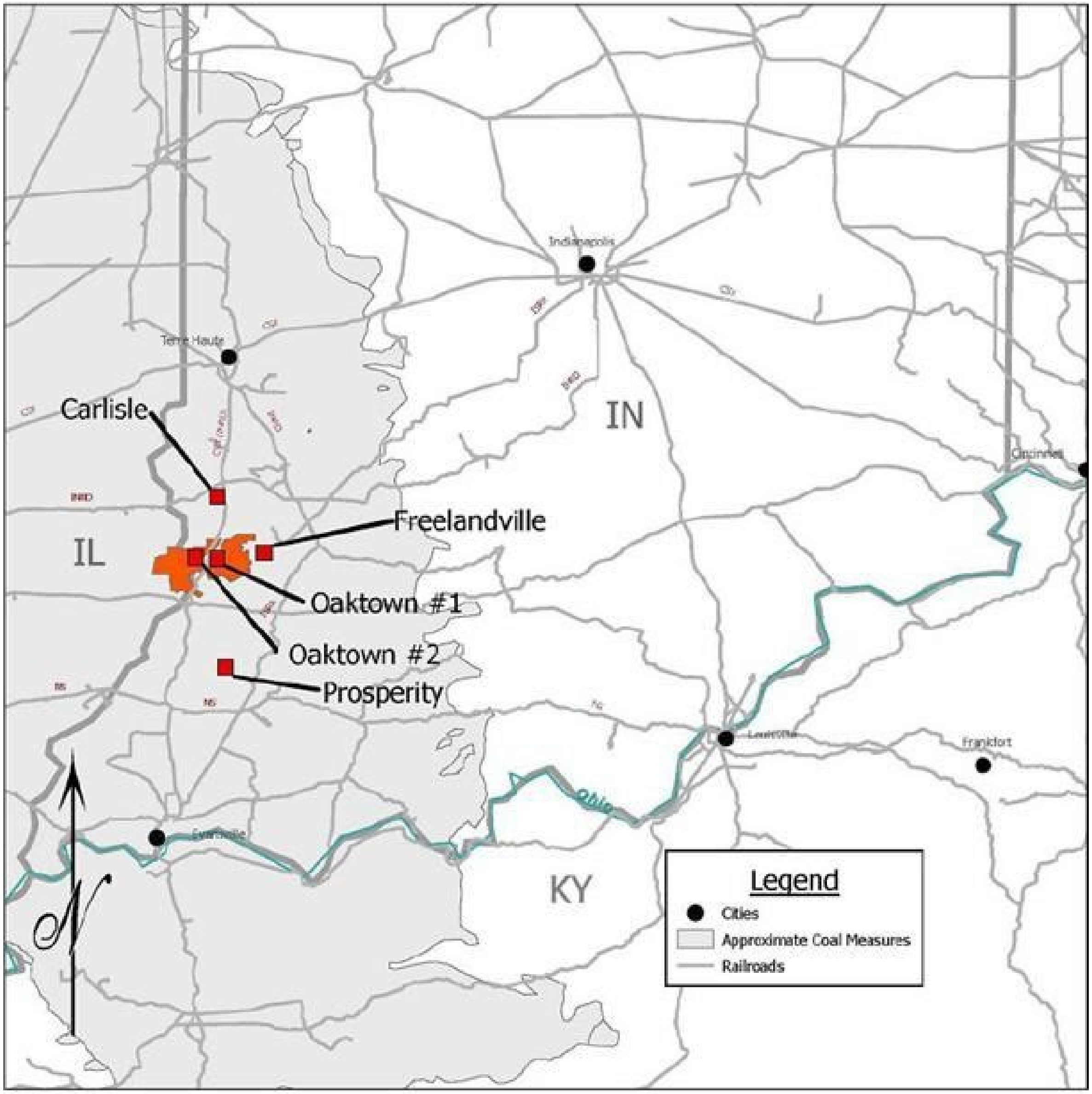
Estimates of any mineral reserve and resources are always subject to a degree of uncertainty. The level of confidence that can be applied to a particular estimate is a function of, among other things, the amount, quality, and completeness of exploration data; geological complexity of the deposit; and economic, legal, social, and environmental factors associated with mining the reserve/resource. The Company's current coal reserves and resource estimates are based on the best information available and are subject to updates as conditions change. Also refer to "Item 1A. Risk Factors" for discussion of risks associated with the estimates of the Company's reserves and resources.

Summary of All Mining Properties

The Company has six total mining properties. These properties are the Oaktown Mining Complex, which is comprised of Oaktown Fuels No. 1 Mine and Oaktown Fuels No. 2 Mine, the Ace in the Hole Mine, the Ace in the Hole Mine #2 Reserves, Prosperity and Freelandville. The Oaktown Fuels No. 1 Mine is an underground mine in the Illinois Basin located near Oaktown in Knox County, Indiana. Oaktown Fuels No. 1 Mine utilizes continuous mining units operating in room and pillar mining techniques to produce high-sulfur coal. The Oaktown Fuels No. 2 Mine is an underground mine in the Illinois Basin located near Oaktown in Knox County, Indiana. The Oaktown Fuels No. 2 Mine utilizes continuous mining units operating in room and pillar mining techniques to produce high-sulfur coal. The preparation plant at the Oaktown Mine Complex has a throughput capacity of 1,600 tons of raw coal per hour. Freelandville is a surface mine in the Illinois Basin located near Freelandville in Knox County, Indiana. Freelandville utilizes surface mining techniques to produce high-sulfur coal from as many as three seams. Prosperity is a surface mine in the Illinois Basin located near Petersburg in Pike County, Indiana. Prosperity utilizes surface mining techniques to produce low-sulfur coal. The low-sulfur coal is trucked to the Oaktown Complex and other Sunrise Coal logistic facilities where it is blended with coal from the Oaktown Mines. Ace in the Hole Mine is now depleted.

These properties and further summaries concerning property description, purpose, property overview, geology, background, processing operations, mine infrastructure, and market analysis can be found and are hereby incorporated by reference from Sections 1.1, 1.2, 1.3, 1.6, 2.1, 3, 4, 5, 6, 7.1, 7.3, 7.4, 8, 9, and 10 from the October 2023 Technical Report Summary prepared by the John T. Boyd Company, attached as Exhibit 99.1 to this Form 10-K.

The following figure shows the general location of All Mining Properties discussed above:



Individual Mining Properties

The following information concerning our mining properties has been prepared in accordance with the requirements of subpart 1300 of Regulation S-K. Subpart 1300 of Regulation S-K requires us to disclose our mineral (coal) resources, which we have none, in addition to our mineral (coal) reserves, as of the end of our most recently completed fiscal year both in the aggregate and for each of our individually material mining properties.

As used in this Annual Report on Form 10-K, the terms “mineral resources,” “mineral reserve,” “proven mineral reserve” and “probable mineral reserve” are defined and used in accordance with subpart 1300 of Regulation S-K. Under subpart 1300 of Regulation S-K, mineral resources may not be classified as “mineral reserves” unless the determination has been made by a qualified person (QP) that the mineral resources can be the basis of an economically viable project. You are specifically cautioned not to assume that any part or all of the mineral deposits (including any mineral resources) in these categories will ever be converted into mineral reserves, as defined by the SEC.

Internal qualified person(s) have estimated the Company's mineral reserves and mineral resources based on geologic data, coal ownership (control) information, and current and/or proposed operating plans. Periodic updates occur to mineral reserve and mineral resource estimates attributable to revised mine plans, new exploration data, depletion from coal production, property acquisitions or dispositions, and/or other geologic or mining data. Sunrise's estimates of mineral reserves are proven and probable reserves that could be extracted or produced at the time of the reserve determination, economically, legally, and after considering all material modifying factors. Modifications or updates of the estimates of the Company's mineral reserves is limited to qualified geologists and mining engineers. All modifications or updates of the estimates of recoverable coal reserves are documented. The John T. Boyd Company, a qualified person firm, has assessed the Company's estimates of mineral reserves and mineral resources and supporting information. Based upon the review, John T. Boyd Company provided modification to the Company's estimates of mineral reserves where warranted.

The information that follows is derived, for the most part, from, and in some instances is extracted from, the Oaktown Mining Complex technical report summary ("TRS") from John T. Boyd Company dated October, 2023 in accordance with Subpart 1300 of Regulation S-K (Coal Resources and Coal Reserves, Oaktown Mining Complex) attached hereto as Exhibit 99.1 to this Form 10-K; and a letter, dated January, 29, 2024, from John T. Boyd Company providing an update of estimated coal reserves at the Oaktown Mining Complex as of December 31, 2023, attached as Exhibit 99.2 to this Form 10-K. The Oaktown Mining Complex is the Company's individually material property. Sections of the following information provided herein do not fully describe assumptions, qualifications, and procedures. Reference should be made to the full text of the TRS which is made a part of this Annual report on Form 10-K and incorporated hereby by reference. The Oaktown Mining Complex TRS was prepared by the John T. Boyd Company in compliance with the Item 60(b)(96) and subpart 1300 of Regulation S-K.

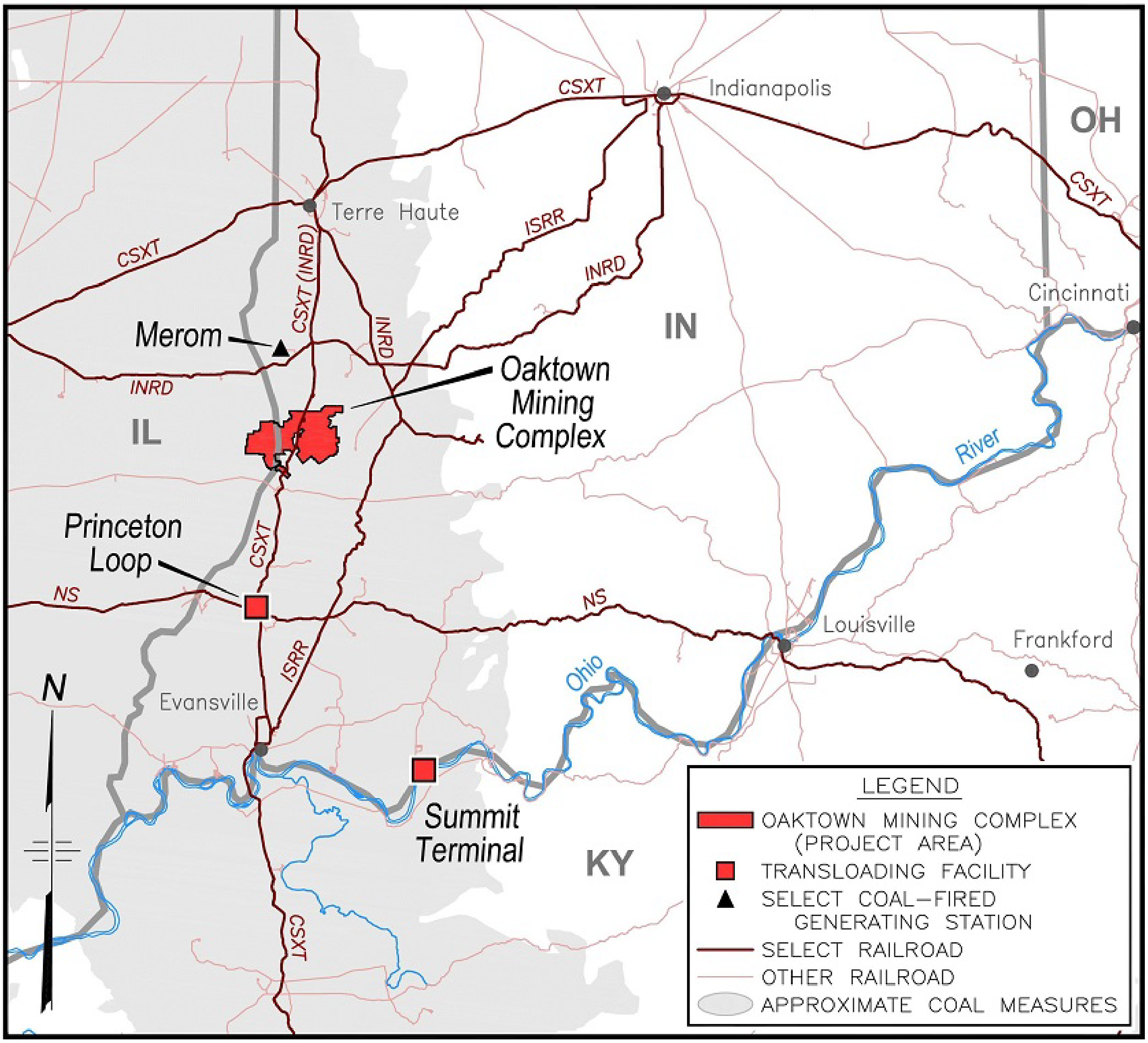
The Company hereby incorporates by reference Section 6.3 "Coal Reserves" from the TRS, attached as Exhibit 99.1 to this Form 10-K, as to the mineral price, cut-off grade, and metallurgical recovery factors utilized in John T. Boyd Company's preparation of the mineral reserve estimates. The Company hereby incorporates the letter, dated January 29, 2024, from John T. Boyd Company, attached as Exhibit 99.2 to this Form 10-K, providing an update of the Company's mineral reserves at the Oaktown Mining Complex as of December 31, 2023 and including a comparison of the Company's mineral reserves at the Oaktown Mining Complex as of December 31, 2023 and as of December 31, 2022. The following table provides a summary of all of the Company's mineral reserves determined by the John T. Boyd Company as of the end of the fiscal year ended December 31, 2023:

SUMMARY MINERAL RESERVES AT END OF THE FISCAL YEAR ENDED DECEMBER 31, 2023

	Mineral Reserves (tons in millions)		
	Proven	**Probable**	**Total**
Oaktown Mining Complex			
Oaktown Fuels No. 1 Mine	29.9	4.2	34.1
Oaktown Fuels No. 2 Mine	20.4	6.2	26.6
Total	50.3	10.4	60.7

Oaktown Mining Complex

The Oaktown Mining Complex is a coal mining and processing operation located in Knox and Sullivan counties, Indiana, and Crawford and Lawrence counties, Illinois. The following figure shows the general location of the Oaktown Mining Complex:



Comprising 118 square miles within the ILB coal-producing region of the mid-western U.S., the Oaktown Mining Complex is one of the largest underground Room-and-Pillar (R&P) coal mining complexes in North America. The Oaktown Mining Complex operations currently consist of two active underground mines - Oaktown Fuels No. 1 Mine and Oaktown Fuels No. 2 Mine - and related infrastructure. Geographically, the Oaktown Complex Coal Preparation Plant is located at approximately 28°51’24.7” N latitude and 87°25’30.9” W longitude. Within the Oaktown Mining Complex area and immediate vicinity, our Company controls approximately 75,000 acres of mineral rights. This control exists as a complex collection of leases that apply to more than 2,000 tracts. Each of which range from less than an acre to several hundred acres in size. Ownership of the surface rights and the mineral rights is often severed for the properties and the estates are often fractions, in which mineral rights are split between several owners. The Company and its predecessors have acquired the necessary rights to support development and operations through purchase or lease agreements with predominately private owners or entities. As part of the Oaktown Mining Complex, the Company controls surface rights through fee simple ownership for over 1,700 permitted acres. Upon those acres resides the surface facilities for mine accesses, processing, storing, shipping, and refuse disposal facilities (i.e., refuse impoundment site and fine refuse injection sites). Our involvement with the Oaktown Mining Complex dates to 2014 with the acquisition of Oaktown Fuels No. 1 and No. 2 Mines from Vectren Fuels.

Each mine of the Oaktown Mining Complex utilizes R&P mining (employing Continuous Miners, or CM) for primary production. This mining method is highly productive and commercially demonstrated; it has been one of the primary approaches to underground mining the Indiana V Seam for decades. Oaktown Mining Complex has utilized this mining method since the inception of each operation. To date, Oaktown Mining Complex has produced a combined 71.1 million tons of clean coal. The complex is configured to operate up to 7 CM sections, with an annual production target of approximately 4.5 million product tons. The Oaktown Complex Coal Preparation Plant serves as the coal washing and shipment facility for the Oaktown Mining Complex's two R&P mines. The plant was commissioned in 2009 to wash coal by the Oaktown Fuels No. 1 Mine. The Oaktown Complex Coal Preparation Plant's processing capacity was upgraded to 1,800 raw tons-per-hour (TPH) from its previous 1,600 raw TPH. Product coal from the Oaktown Mining Complex is transported to its customer base via rail, truck, or a combination of both. The Oaktown Complex Coal Preparation Plant is served by both the CSX Railroad and Indiana Railroad (INRD) via a rail spur and rail loop that connects the complex with the mainline rail just north of Oaktown, Indiana.

Additionally, the Oaktown Complex Coal Preparation Plant can facilitate the loading of trucks for direct transport to select customers, or to our transload facility in Princeton, Indiana serviced by the Norfolk Southern (NS) Railroad.

Sources of electrical power, water, supplies, and materials are readily available. Electrical power is provided to the mines and facilities by regional utility companies. Water is supplied by public water services, surface impoundments, or water wells.

Multiple permits are required by federal and state law for underground mining, coal preparation and related facilities, and other incidental activities. All necessary permits to support current operations are in place or pending approval. New permits or permit revisions may be necessary from time to time to facilitate future operations. Given sufficient time and planning, we should be able to secure new permits, as required, to maintain our planned operations within the context of the current regulations.

Permits generally require that the Company post a performance bond in an amount established by the regulator program to: (1) provide assurance that any disturbance or liability created during mining operation is properly mitigated, and (2) assure that all regulation requirements of the permit are fully satisfied. We hold surety bonds of $9.9 million to cover obligations relating to mining and reclamation, road repair, etc. at the Oaktown Mining Complex.

Additional information is provided in the following table regarding the Oaktown Mining Complex mineral reserves:

OAKTOWN MINING COMPLEX
Recoverable Coal Reserves as of December 31, 2023 and 2022

Mine/Reserve	As Received Heat Value (Btu/lb) Approximate	As Received SO2 Content (lbs/MMBtu) Approximate	Owned (%)	Leased (%)	Recoverable Coal Reserves (As-Received) Proven	Probable	12/31/2023	12/31/2022
Oaktown Mining Complex								
Oaktown Fuels No. 1 Mine	11,527	6.0	—	100.0	29.9	4.2	34.1	36.7
Oaktown Fuels No. 2 Mine	11,518	5.4	—	100.0	20.4	6.2	26.6	29.6
Total					50.3	10.4	60.7	66.3

Oaktown Fuels No. 1 Mine

As of December 31, 2023, the assigned and accessible reserve base for the Oaktown Fuels No. 1 Mine contains 34.1 million tons of recoverable Indiana V seam coal, of which 34.1 million tons are currently permitted. The reserve contains saleable tons which average heating content of approximately 11,527 Btu per pound with approximately 6.0 pounds of sulfur dioxide per MMBtu on an as-received basis. Access to the Oaktown Fuels No. 1 Mine is via a 90-foot-deep box cut and a 2,200-foot long slope, which facilitates the egress of coals being mined in excess of 375 feet below the surface. Since beginning first commercial coal production in 2009, the mine workings have substantially grown, and an additional mine access (elevator) was constructed for employee and supply ingress/egress closer to the active production faces.

Oaktown Fuels No. 2 Mine

As of December 31, 2023, the assigned and accessible reserve base for the Oaktown Fuels No. 2 Mine contains 26.6 million tons of recoverable Indiana V seam coal, of which 21.3 million tons are currently permitted. The reserve contains saleable tons which average heating content of approximately 11,518 Btu per pound with approximately 5.4 pounds of sulfur dioxide per MMBtu on an as-received basis. Access to the Oaktown Fuels No. 2 Mine is via an 80-foot-deep box cut and 2,600-foot long slope, which facilitates the egress of coals being mined in excess of 400 feet below the surface. Since beginning first commercial coal production in 2013 the mines workings have substantially grown and, during 2021, an additional mine access (elevator) was constructed for employee and supply ingress/egress closer to the active production faces.

Tonnages are reported on a clean recoverable basis with average long-term pricing based on available third-party forecasts and historical pricing adjusted for quality at the end of 2023, with the coal sales price estimated over the life of the reserve averaging approximately $47 (ranging from $42.50 to $64 per short ton), which are the coal sales prices used by John T. Boyd Company to estimate the amount of coal mineral reserves for the Oaktown Fuels No. 1 Mine and Oaktown Fuels No. 2 Mine as listed above. Coal sales prices vary based on coal quality, access to transportation, and other factors at each location. All reserves are classified as underground mineable in the production stage.

The Company hereby incorporates by reference (i) the TRS, attached as Exhibit 99.1 to this Form 10-K, including Section 6.3 thereof titled "Coal Reserves", as to the recoverable coal reserves reported above for the Oaktown Fuels No. 1 Mine and Oaktown Fuels No. 2 Mine; and (ii) letter, dated January 29, 2024, from John T. Boyd Company, attached as Exhibit 99.2 to this Form 10-K, providing an update of the Company's mineral reserves at the Oaktown Mining Complex as of December 31, 2023 and including a comparison of the Company's mineral reserves at the Oaktown Mining Complex as of December 31, 2023 and as of December 31, 2022.

Historical production for our Oaktown Mining Complex during the years ended December 31, 2023, 2022, and 2021 is provided in the following table:

	Annual Saleable Production Tons (Million Tons)		
Mine/Reserve	**2023**	**2022**	**2021**
Oaktown Mining Complex			
Oaktown Fuels No. 1 Mine	3.9	3.9	3.5
Oaktown Fuels No. 2 Mine	2.5	2.5	2.1
Total Oaktown Mining Complex Production	6.4	6.4	5.6

Other Properties

The Company holds other recoverable coal reserves in the ILB, which are not deemed individually material.

<u>Ace in the Hole Mine (Ace) (surface) – Assigned</u>

Ace Mine is now depleted. Remaining inventory of coal and base was moved to our Carlisle and Oaktown wash plants in early 2023. Reclamation resumed in the Spring of 2023. Phase 1 and 2 reclamation is substantially complete as of December 31, 2023.

<u>Prosperity (surface) – Assigned</u>

The Prosperity mine contains approximately 0.2 million tons of low sulfur coal needed to blend with our Oaktown coal to reduce the sulfur content to a salable level for Southeastern US markets. The mine opened in the summer of 2022. The mine produced coal and reclaimed the slurry pond and refuse pile left by the Prosperity underground mine. Additional reserves are in the area that may extend the life of this mine. In February 2024, this mine was temporarily idled.

<u>Freelandville (surface) – Assigned</u>

Sunrise is a contract miner at the Freelandville East Mine Center Pit, Permit No. S 358. Sunrise had an option through May 31, 2023 to assume the permit that contained approximately 1.7 million tons of salable coal with an additional 0.6 million available. Mining started in the fall of 2022 and continued through April 2023. In February 2024, this mine was idled.

Our Coal Contracts

In 2023, on a segment basis Sunrise sold 6.9 million tons of coal to 11 power plants in five different states across six different customers.

During 2023, on a segment basis we derived 94% of our revenue from five customers (11 power plants), with each of the five customers representing at least 10% of our coal sales. During 2022, on a segment basis we derived 90% of our revenue from five customers (10 power plants), with each of the five customers representing at least 10% of our coal sales.

Significant customers in 2023 include Vectren Corporation, a wholly-owned subsidiary of CenterPoint Energy (NYSE: CNP), Orlando Utility Commission (OUC), Alcoa Power Generating, Inc., a subsidiary of Alcoa Corporation (NYSE: AA), Alabama Power, a subsidiary of Southern Company (NYSE: SO), and Duke Energy Corporation (NYSE: DUK).

Of our 2023 sales, on a segment basis 33%, excluding Merom Power Plant, were derived to locations in the State of Indiana.

Our future coal commitments are as follows:

Year	3rd Party Contracted tons (millions)*	Merom Power Plant Contracted tons (millions)*	Total	Estimated Priced per ton
2024	3.4	1.5	4.9	$ 53.91
2025 - 2028 (total)	5.8	9.2	15.0	**
Total	9.2	10.7	19.9	

* Contracted tons are subject to adjustment in instances of force majeure and exercise of customer options to either take additional tons or reduce tonnage if such option exists in the customer contract.

** Unpriced or partially priced committed tons

As of December 31, 2023, we are committed to supplying third-party customers up to a maximum of 9.2 million tons of coal through 2027 of which 6.2 million tons are priced. We are committed to supplying coal to Merom Power Plant up to a maximum of 10.7 million tons of coal through 2028. All committed tons to Merom are priced.

Based on the contracted tons described above, we anticipate our mines will need to produce at a 4.5 million ton annualized pace for the foreseeable future to meet the Merom plant and third-party market demand.

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.

Some utility customers have proposed shuttering certain plant units or entire plants in the coming years. It remains to be seen whether these plans will be implemented.

Liquidity and Capital Resources

As set forth in our Consolidated Statements of Cash Flows, cash provided by operations was $59.4 million and $54.2 million for the years ended December 31, 2023 and 2022 respectively. Operating cash flow increased due to an increase in operating margins at our coal mines brought on by the addition of higher priced contracts. This was offset by lower margins from our power plant and a decrease in working capital.

Our capital expenditure budget for 2024 is $43 million, of which the majority is for maintenance capex. Of the $43 million, the budget for coal operations is $25 million and the budget for electric operations is $18 million.

As of December 31, 2023, our bank debt was $91.5 million. On March 13, 2023, we executed an amendment to our credit agreement with PNC Bank, National Association (in its capacity as administrative agent, “PNC”), administrative agent for our lenders under our credit agreement. The primary purpose of the amendment was to convert $35 million of the revolver into a new term loan with a maturity of March 31, 2024, and extend the maturity date of the revolver to May 31, 2024. On August 2, 2023, we executed an additional amendment with PNC. The primary purpose of the amendment was to convert $65 million of the existing outstanding debt into a new term loan with a maturity of March 31, 2026, and enter into a revolver of $75 Million with a maturity date of July 31, 2026. Principal payments for the term loan were $3.3 million per quarter for September 30, 2023, and December 31, 2023, and $6.5 million per quarter starting March 31, 2024, through maturity. The effect of the amendment on our future cash flow is to extend the maturity date of $65.0 million of our outstanding debt to May 31, 2026, and our revolver to July 31, 2026.

We expect cash from operations generated primarily by our expected higher coal margins in 2023 to fund our capital expenditures and our debt service.

See Note 4 to our consolidated financial statements for additional discussion about our bank debt and related liquidity.

Off-Balance Sheet Arrangements

Other than our surety bonds for reclamation, we have no material off-balance sheet arrangements. We have recorded the present value of reclamation obligations of $16.6 million, including $5.2 million at Merom, presented as asset retirement obligations (ARO) in our accompanying balance sheets. In the event we are not able to perform reclamation, we have surety bonds in place totaling $37.5 million to cover ARO.

Capital Expenditures (capex)

For the year ended December 31, 2023, our capex was $75.4 million allocated as follows (in millions):

Oaktown – maintenance capex	$	36.2
Oaktown – investment		18.3
Prosperity mine		0.8
Freelandville mine		1.2
Merom plant		18.8
Other		0.1
Capex per the Consolidated Statements of Cash Flows	$	75.4

Results of Operations

Presentation of Segment Information

Our operations are divided into two primary reportable segments: Coal Operations and Electric Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as “Corporate and Other” within the Notes to the Consolidated Financial Statements and primarily are comprised of unallocated corporate costs and activities, including a 50% interest in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana, which we account for using the equity method, and our wholly-owned subsidiary Summit Terminal LLC, a logistics transport facility located on the Ohio River.

Coal Operations

		2023		2022
OPERATING REVENUES:	$	435,425	$	293,344
EXPENSES:				
Operating expenses		311,041		236,416
Depreciation, depletion and amortization		48,365		43,612
Asset retirement obligations accretion		1,228		1,010
Exploration costs		904		651
General and administrative		10,287		7,919
Total operating expenses		371,825		289,608
INCOME (LOSS) FROM OPERATIONS	$	63,600	$	3,736

Operating revenues from coal operations increased 48% over 2022 due in large part to unprecedented increases in natural gas prices. As a result, higher priced contracts sold in the summer of 2022 and delivered in Q4 of 2022 through all of 2023 increased our average sales price by $16.90 per ton from 2022. We also sold 581,000 additional tons over 2022 at the higher average price due to lower inventories and the higher gas prices.

Operating expenses increased, however, by ~$7.50 per ton. The addition of the higher cost Freelandville and Prosperity surface mines as well as significant inflationary pressures and geological conditions contributed significantly to the increased costs. Depreciation, depletion, and amortization increased 11%. The majority of this change is due to significant capital additions in the coal division.

General and administrative expenses increased 30% over 2022 due in large part to additional professional fees related to bank refinancing and additional audit requirements. Increased wages due to bonuses and incentives to retain and attract talent also contributed to the increased costs.

Electric Operations

		2023		2022
OPERATING REVENUES:	$	268,341	$	66,316
EXPENSES:				
Operating expenses		231,560		29,608
Depreciation, depletion and amortization		18,739		3,117
Asset retirement obligations accretion		576		—
General and administrative		4,914		2,086
Total operating expenses		255,789		34,811
INCOME FROM OPERATIONS	$	12,552	$	31,505

A comparative discussion is not relevant as the Electric Operations did not begin until the Merom Acquisition closed in October 2022.

Operating revenue is derived from sales to the Midcontinent Independent System Operator ("MISO") wholesale market and a power purchase agreement (PPA) signed with Hoosier in conjunction with the Merom Acquisition. The PPA included sales at fixed prices which were below market prices at the date we entered into the agreement. The power purchase agreement expires in 2025 and requires us to provide a fixed amount of power over the term of the agreement. As a result of the below market contract, we recorded a contract liability at the close of the acquisition totaling $184.5 million that will be amortized over the term of the agreement as the contract is fulfilled. For the years ended December 31, 2023, we recorded $70.5 million and $23.3 million, respectively of revenue as a result of amortizing the contract liability.

Operating expenses include coal purchased under an agreement signed with Hoosier in conjunction with the Merom acquisition at fixed prices which were below market prices at the date we entered into the agreement. The coal purchase agreement expired in May 2023 and required us to purchase a fixed amount of coal over the term of the agreement. As a result of the below market contract, we recorded a contract asset at the close of the acquisition totaling $34.3 million that was amortized over the term of the agreement as the contract was fulfilled. The contract asset was fully amortized with an asset value of $0 as of December 31, 2023. For the years ended December 31, 2023 and 2022, we recorded $30.7 million and $3.6 million respectively in additional operating expense for coal purchased and used.

The following tables presenting our quarterly results of operations should be read in conjunction with the consolidated financial statements and related notes included in Item 8 of this 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 tables present our unaudited quarterly results of operations for the eight quarters ended December 31, 2023, and include all adjustments, consisting only of normal recurring adjustments, that we consider necessary for fair presentation of our consolidated operating results for the quarters presented.

	Mar-31 2023	Jun-30 2023	Sep-30 2023	Dec-31 2023	Total 2023
SALES AND OPERATING REVENUES:					
Coal sales	$ 94,602	$ 88,574	$ 97,420	$ 81,330	$ 361,926
Electric sales	92,392	71,017	67,403	37,115	267,927
Other revenues	1,340	1,603	945	739	4,627
Total revenue	188,334	161,194	165,768	119,184	634,480
EXPENSES:					
Operating expenses	133,521	115,420	119,042	105,407	473,390
Depreciation, depletion and amortization	17,976	17,169	16,230	15,836	67,211
Asset retirement obligations accretion	451	461	468	424	1,804
Exploration costs	206	305	171	222	904
General and administrative	6,947	5,595	6,054	7,563	26,159
Total operating expenses	159,101	138,950	141,965	129,452	569,468
INCOME (LOSS) FROM OPERATIONS	29,233	22,244	23,803	(10,268)	65,012
Bank debt and other interest	(3,899)	(3,541)	(3,030)	(3,241)	(13,711)
Loss on extinguishment of debt	—	—	(1,491)	—	(1,491)
Equity method investment income	69	(217)	(177)	(227)	(552)
INCOME (LOSS) BEFORE INCOME TAXES	25,403	18,486	19,105	(13,736)	49,258
INCOME TAX EXPENSE (BENEFIT):					
Current	432	61	(178)	(479)	(164)
Deferred	2,920	1,510	3,208	(3,009)	4,629
Total income tax expense (benefit)	3,352	1,571	3,030	(3,488)	4,465
NET INCOME (LOSS)	$ 22,051	$ 16,915	$ 16,075	$ (10,248)	$ 44,793
NET INCOME (LOSS) PER SHARE:					
Basic	$ 0.67	$ 0.51	$ 0.49	$ (0.31)	$ 1.35
Diluted	$ 0.61	$ 0.47	$ 0.44	$ (0.31)	$ 1.25
WEIGHTED AVERAGE SHARES OUTSTANDING:					
Basic	32,983	33,137	33,140	33,245	33,133
Diluted	36,740	36,708	36,848	33,245	36,827

	Mar-31 2022	Jun-30 2022	Sep-30 2022	Dec-31 2022	Total 2022
SALES AND OPERATING REVENUES:					
Coal sales	$ 57,010	$ 64,161	$ 83,562	$ 84,643	$ 289,376
Electric sales	—	—	—	66,252	66,252
Other revenues	1,897	1,768	1,522	1,176	6,363
Total revenue	58,907	65,929	85,084	152,071	361,991
EXPENSES:					
Operating expenses	54,601	51,394	64,557	96,056	266,608
Depreciation, depletion and amortization	9,531	11,164	11,187	14,993	46,875
Asset retirement obligations accretion	246	250	255	259	1,010
Exploration costs	57	215	121	258	651
General and administrative	3,149	3,722	3,569	5,977	16,417
Total operating expenses	67,584	66,745	79,689	117,543	331,561
INCOME (LOSS) FROM OPERATIONS	(8,677)	(816)	5,395	34,528	30,430
Bank debt and other interest	(1,710)	(1,770)	(2,360)	(2,438)	(8,278)
Amortization and swap related interest	(74)	(567)	(995)	(1,098)	(2,734)
Equity method investment income	150	188	168	(63)	443
INCOME (LOSS) BEFORE INCOME TAXES	(10,311)	(2,965)	2,208	30,929	19,861
INCOME TAX EXPENSE (BENEFIT):					
Current	—	—	—	—	—
Deferred	(177)	421	596	916	1,756
Total income tax expense (benefit)	(177)	421	596	916	1,756
NET INCOME (LOSS)	$ (10,134)	$ (3,386)	$ 1,612	$ 30,013	$ 18,105
NET INCOME (LOSS) PER SHARE:					
Basic	$ (0.33)	$ (0.11)	$ 0.05	$ 0.91	$ 0.57
Diluted	$ (0.33)	$ (0.11)	$ 0.05	$ 0.83	$ 0.55
WEIGHTED AVERAGE SHARES OUTSTANDING:					
Basic	30,785	30,785	32,983	32,983	32,043
Diluted	30,785	30,809	33,268	36,428	33,649

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

All Mines	1st 2023	2nd 2023	3rd 2023	4th 2023	T4Qs
Tons produced	2,006	1,723	1,594	1,331	6,654
Tons sold	1,693	1,714	2,054	1,461	6,922
Coal sales	$ 94,602	$ 112,171	$ 134,400	$ 91,714	$ 432,887
Average price per ton	$ 55.88	$ 65.44	$ 65.43	$ 62.77	$ 62.54
Wash plant recovery in %	70%	67%	65%	62%	
Operating costs	$ 65,700	$ 71,168	$ 95,592	$ 78,581	$ 311,041
Average cost per ton	$ 38.81	$ 41.52	$ 46.54	$ 53.79	$ 44.94
Margin	$ 28,902	$ 41,003	$ 38,808	$ 13,133	$ 121,846
Margin per ton	$ 17.07	$ 23.92	$ 18.89	$ 8.99	$ 17.60
Capex	$ 12,639	$ 14,445	$ 11,570	$ 17,867	$ 56,521
Maintenance capex	$ 7,778	$ 9,754	$ 7,938	$ 13,567	$ 39,037
Maintenance capex per ton	$ 4.59	$ 5.69	$ 3.86	$ 9.29	$ 5.64

All Mines	1st 2022	2nd 2022	3rd 2022	4th 2022	T4Qs
Tons produced	1,397	1,762	1,663	1,721	6,543
Tons sold	1,377	1,595	1,705	1,664	6,341
Coal sales	$ 57,010	$ 64,161	$ 83,563	$ 84,641	$ 289,375
Average price per ton	$ 41.40	$ 40.23	$ 49.01	$ 50.87	$ 45.64
Wash plant recovery in %	67%	71%	69%	68%	
Operating costs	$ 54,443	$ 50,776	$ 63,876	$ 67,319	$ 236,414
Average cost per ton	$ 39.54	$ 31.83	$ 37.46	$ 40.46	$ 37.28
Margin	$ 2,567	$ 13,385	$ 19,687	$ 17,322	$ 52,961
Margin per ton	$ 1.86	$ 8.39	$ 11.55	$ 10.41	$ 8.35
Capex	$ 9,082	$ 13,821	$ 15,096	$ 12,368	$ 50,367
Maintenance capex	$ 4,481	$ 7,600	$ 6,625	$ 5,748	$ 24,454
Maintenance capex per ton	$ 3.25	$ 4.76	$ 3.89	$ 3.45	$ 3.86

Quarterly electric sales and cost data (in thousands, except per MWh data) are provided below. Fixed costs in the table are considered "non-GAAP" and are a component of operating expenses, the most comparable GAAP measure. We consider fixed costs to be costs associated with the plant whether or not the plant is in operation.

	1st 2023	2nd 2023	3rd 2023	4th 2023	2023
MWh sold	1,262	1,043	1,307	612	4,224
Capacity revenue	$ 15,970	$ 17,155	$ 13,012	$ 10,018	$ 56,155
Delivered energy and PPA revenue	76,422	53,862	54,391	27,097	211,772
Total electric sales	92,392	71,017	67,403	37,115	267,927
Less amortization of contract liability	(33,347)	(19,555)	(10,281)	(7,347)	(70,530)
Total electric sales less amortization of contract liability	$ 59,045	$ 51,462	$ 57,122	$ 29,768	$ 197,397
Average price/MWh of delivered energy and PPA revenue less amortization of contract liability	$ 34.13	$ 32.89	$ 33.75	$ 32.27	$ 35.18
Operating expenses (on a segment basis)	$ 67,682	$ 55,996	$ 64,172	$ 43,710	$ 231,560
Less fixed costs	(12,807)	(11,693)	(11,858)	(22,259)	(58,617)
Less amortization of contract asset	(17,778)	(12,962)	-	-	(30,740)
Operating expenses less fixed costs and amortization of contract asset	$ 37,097	$ 31,341	$ 52,314	$ 21,451	$ 142,203
Average variable cost/MWh of operating expenses less fixed costs and amortization of contract asset	$ 29.40	$ 30.05	$ 40.03	$ 35.05	$ 33.44
Energy and PPA margin less fixed costs and amortization of contract asset and liabilities	$ 5,978	$ 2,966	$ (8,204)	$ (1,701)	$ (961)
Energy & PPA margin/MWh less fixed costs amortization of contract asset and liabilities	$ 4.74	$ 2.84	$ (6.28)	$ (2.78)	$ (0.23)

Critical Accounting Estimates

We believe that the estimates of coal reserves, asset retirement obligation liabilities, deferred tax accounts, valuation of inventory, treatment of business combinations, and the estimates used in impairment analysis are our critical accounting estimates.

The reserve estimates are used in the depreciation, depletion and amortization calculations and our internal cash flow projections. If these estimates turn out to be materially under or over-stated, our depreciation, depletion and amortization expense and impairment test may be affected. The process of estimating reserves is complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. The reserve estimates are prepared by professional engineers, both internal and external, and are subject to change over time as more data becomes available. Changes in the reserves estimates from the prior year were nominal.

SMCRA and similar state statutes require, among other things, that surface disturbance be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore affected surface areas 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.

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 (proven and probable) reserves. We use credit-adjusted risk-free discount rates ranging from 7% to 10% to discount the obligation, inflation rates anticipated during the time to reclamation, and cost estimates prepared by its engineers inclusive of market risk premiums. Activities include reclamation of pit and support acreage at surface mines, sealing portals at underground mines, and reclamation of refuse areas and slurry ponds.

Accretion expense is recognized on the obligation through the expected settlement date. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing and extent of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled.

We 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 would be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. We have not taken any significant uncertain tax positions and our tax provision and returns are prepared by a large public accounting firm with significant experience in energy related industries. Changes to the estimates from reported amounts in the prior year were not significant.

Inventory is valued at lower of cost or net realizable value (NRV). Anticipated utilization of low sulfur, higher-cost coal from our Freelandville, and Prosperity mines has the potential to create NRV adjustments as our estimated needs change. The NRV adjustments are subject to change as our costs may fluctuate due to higher or lower production and our NRV may fluctuate based on sales contracts we enter into from time to time. There were no significant changes to our NRV adjustment estimates from the prior year.

We account for business acquisitions as either asset acquisitions or business combination depending on the circumstances as outlined in ASC 805-50. For acquisitions accounted for as a business combination, we record the assets acquired, including identified intangible assets and liabilities assumed at their fair value. For acquisitions accounted for as asset acquisitions, we allocate the fair value of consideration exchanged in the transaction to each of the acquired assets based upon their relative fair value. Fair value in many instances involves estimates based on third-party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques. Those estimates are subject to a high degree of uncertainty, thus we typically will retain professionals in the relevant industries of the acquiree to assist us with our analysis and valuations. See “Item 8. Financial Statements - Note 15 - Acquisition” for more information on the Merom Acquisition.

Long-lived assets used in operations are depreciated and assessed for impairment annually or whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows is expected to be generated by an asset group. For impairment assessments, management groups individual assets based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. The determination of the lowest level of cash flows is largely based on nature of production, common infrastructure, common sales points, common regulation and management oversight to make such determinations. These determinations could impact the determination and measurement of a potential asset impairment. Management evaluates assets for impairment through an established process in which changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments of future volumes, commodity prices, operating costs and capital investment plans, considering all available information at the date of review. Changes to any of the market-based assumptions can significantly affect estimates of undiscounted and discounted pre-tax cash flows and impact the recognition and amount of impairments.

ITEM 8. FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Hallador Energy Company

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Hallador Energy Company (a Colorado corporation) and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, cash flows and stockholders' equity for each of the two years in the period ended December 31, 2023, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 14, 2024 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

<u>Asset retirement obligations</u>

As of December 31, 2023, the Company's asset retirement obligations totaled $16.7 million. As described further in Note 1 to the consolidated financial statements, the Company's asset retirement obligations are associated with retirement of long-lived assets and recognized at fair value at the time the obligations are incurred. The Company reviews its asset retirement obligations at least annually and makes necessary adjustments for revisions of inputs and assumptions utilized in the calculations. The calculation of asset retirement obligations requires significant management judgement due to the inherent complexity in estimating the amount and timing of future reclamation activities. We identified the accounting for the asset retirement obligations as a critical audit matter.

The principal consideration for our determination that the accounting for the asset retirement obligations is a critical audit matter is that management utilized significant judgment in determining the amount of asset retirement obligations. In particular, the obligations value is estimated based upon a discounted cash flow technique and includes inputs and assumptions related to reclamation costs and the timing of reclamation activities. Accordingly, auditing management’s assumptions involved a high degree of subjectivity due to the uncertainty of management’s significant judgements.

Our audit procedures related to the accounting for asset retirement obligations included the following, among others:

- We tested the design and operating effectiveness of internal controls over the asset retirement obligations estimation and recognition process.
- We assessed the reasonableness of the Company's methodology to calculate asset retirement obligations.
- We tested the completeness and accuracy of the underlying data used in management's asset retirement obligations calculation.
- We evaluated the reasonableness of significant judgements including inflation rate, credit-adjusted risk-free rate, reclamation cost estimates and timing of expected reclamation activities.
- We interviewed the Company's professionals with specialized skill and knowledge regarding the regulatory requirements and mine plans.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2022.

Tulsa, Oklahoma
March 14, 2024

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

Hallador Energy Company
Consolidated Balance Sheets
As of December 31,
(in thousands)

		2023		2022
ASSETS				
Current assets:				
Cash and cash equivalents	$	2,842	$	3,009
Restricted cash		4,281		3,417
Accounts receivable		19,937		29,889
Inventory		23,075		49,796
Parts and supplies		38,877		28,295
Contract asset - coal purchase agreement		—		19,567
Prepaid expenses		2,262		4,546
Total current assets		91,274		138,519
Property, plant and equipment:				
Land and mineral rights		115,486		115,595
Buildings and equipment		537,131		534,129
Mine development		158,642		140,108
Finance lease right-of-use assets		12,346		—
Total property, plant and equipment		823,605		789,832
Less - accumulated depreciation, depletion and amortization		(334,971)		(309,370)
Total property, plant and equipment, net		488,634		480,462
Investment in Sunrise Energy		2,811		3,988
Other assets		7,061		7,585
Total assets	$	589,780	$	630,554
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Current portion of bank debt, net	$	24,438	$	33,031
Accounts payable and accrued liabilities		62,908		82,972
Current portion of lease financing		3,933		—
Deferred revenue		23,062		35,485
Contract liability - power purchase agreement and capacity payment reduction		43,254		88,114
Total current liabilities		157,595		239,602
Long-term liabilities:				
Bank debt, net		63,453		49,713
Convertible notes payable		10,000		10,000
Convertible notes payable - related party		9,000		9,000
Long-term lease financing		8,157		—
Deferred income taxes		9,235		4,606
Asset retirement obligations		14,538		17,254
Contract liability - power purchase agreement		47,425		84,096
Other		1,789		1,259
Total long-term liabilities		163,597		175,928
Total liabilities		321,192		415,530
Commitments and contingencies				
Stockholders' equity:				
Preferred stock, $.10 par value, 10,000 shares authorized; none issued		—		—
Common stock, $.01 par value, 100,000 shares authorized; 34,052 and 32,983 issued and outstanding, respectively		341		330
Additional paid-in capital		127,548		118,788
Retained earnings		140,699		95,906
Total stockholders’ equity		268,588		215,024
Total liabilities and stockholders’ equity	$	589,780	$	630,554

The accompanying notes are an integral part of these Consolidated Financial Statements

Hallador Energy Company
Consolidated Statements of Operations
For the years ended December 31,
(in thousands, except per share data)

	2023	2022
SALES AND OPERATING REVENUES:		
Coal sales	$ 361,926	$ 289,376
Electric sales	267,927	66,252
Other revenues	4,627	6,363
Total sales and operating revenues	634,480	361,991
OPERATING EXPENSES:		
Operating expenses	473,390	266,608
Depreciation, depletion and amortization	67,211	46,875
Asset retirement obligations accretion	1,804	1,010
Exploration costs	904	651
General and administrative	26,159	16,417
Total operating expenses	569,468	331,561
INCOME FROM OPERATIONS	65,012	30,430
Interest expense [(1)]	(13,711)	(11,012)
Loss on extinguishment of debt	(1,491)	—
Equity method investment (loss) income	(552)	443
INCOME BEFORE INCOME TAXES	49,258	19,861
INCOME TAX EXPENSE (BENEFIT):		
Current	(164)	—
Deferred	4,629	1,756
Total income tax expense	4,465	1,756
NET INCOME	$ 44,793	$ 18,105
NET INCOME PER SHARE:		
Basic	$ 1.35	$ 0.57
Diluted	$ 1.25	$ 0.55
WEIGHTED AVERAGE SHARES OUTSTANDING:		
Basic	33,133	32,043
Diluted	36,827	33,649

(1) Interest Expense:		
Interest on bank debt	$ 8,636	$ 7,563
Other interest	1,842	715
Amortization and swap related interest:		
Payments on interest rate swap, net of changes in value	—	(867)
Amortization of debt issuance costs	3,233	3,601
Total amortization and swap related interest	3,233	2,734
Total interest expense	$ 13,711	$ 11,012

The accompanying notes are an integral part of these Consolidated Financial Statements

Hallador Energy Company
Consolidated Statements of Cash Flows
For the years ended December 31,
(in thousands)

	2023	2022
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 44,793	$ 18,105
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred income taxes	4,629	1,756
Equity income (loss) – Sunrise Energy	552	(443)
Cash distribution - Sunrise Energy	625	—
Depreciation, depletion and amortization	67,211	46,875
Loss on extinguishment of debt	1,491	—
Loss (gain) on sale of assets	398	(264)
Payments on interest rate swap, net of changes in value	—	(867)
Amortization of debt issuance costs	3,233	3,601
Asset retirement obligations accretion	1,804	1,010
Cash paid on asset retirement obligation reclamation	(3,384)	(3,162)
Stock-based compensation	3,554	1,269
Provision for loss on customer contracts	—	159
Amortization of contract asset and contract liabilities	(39,791)	(19,731)
Change in current assets and liabilities:		
Accounts receivable	9,952	(16,305)
Inventory	15,548	(25,863)
Parts and supplies	(10,582)	(6,271)
Prepaid expenses	1,186	(5,941)
Accounts payable and accrued liabilities	(18,992)	24,037
Deferred revenue	(23,423)	35,485
Other	610	719
Net cash provided by operating activities	$ 59,414	$ 54,169

Hallador Energy Company

Consolidated Statements of Cash Flows

For the years ended December 31,

(in thousands)

(continued)

	2023	2022
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	$ (75,352)	$ (54,020)
Proceeds from sale of equipment	62	655
Net cash used in investing activities	(75,290)	(53,365)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on bank debt	(59,713)	(78,225)
Borrowings of bank debt	66,000	51,700
Proceeds from sale and leaseback arrangement	11,082	—
Issuance of convertible notes payable	—	11,000
Issuance of related party convertible notes payable	—	18,000
Debt issuance costs	(6,013)	(2,097)
Distributions to redeemable noncontrolling interests	—	(585)
ATM offering	7,318	—
Taxes paid on vesting of RSUs	(2,101)	—
Net cash provided by (used in) financing activities	16,573	(207)
Increase in cash, cash equivalents, and restricted cash	697	597
Cash, cash equivalents, and restricted cash, beginning of year	6,426	5,829
Cash, cash equivalents, and restricted cash, end of year	$ 7,123	$ 6,426
CASH, CASH EQUIVALENTS, AND RESTRICTED CASH:		
Cash and cash equivalents	$ 2,842	$ 3,009
Restricted cash	4,281	3,417
	$ 7,123	$ 6,426
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest	$ 9,966	$ 8,123
SUPPLEMENTAL NON-CASH FLOW INFORMATION:		
Change in capital expenditures included in accounts payable and finance lease	$ 1,882	$ 3,440

The accompanying notes are an integral part of these Consolidated Financial Statements

Hallador Energy Company
Consolidated Statement of Stockholders' Equity
(in thousands)

	Common Stock Issued		Additional Paid-in	Retained	Total Stockholders'
	Shares	Amount	Capital	Earnings	Equity
BALANCE, DECEMBER 31, 2021	30,785	$ 308	$ 104,126	$ 77,801	182,235
Stock-based compensation	—	—	1,269	—	1,269
Cancellation of redeemable noncontrolling interests	—	—	3,415	—	3,415
Stock issued on redemption of convertible note	232	2	998	—	1,000
Stock issued on redemption of related party convertible notes	1,966	20	8,980	—	9,000
Net income	—	—	—	18,105	18,105
BALANCE, DECEMBER 31, 2022	32,983	330	118,788	95,906	215,024
Stock-based compensation	—	—	3,554	—	3,554
Stock issued on vesting of RSUs	473	5	(5)	—	—
Taxes paid on vesting of RSUs	(198)	(2)	(2,099)	—	(2,101)
Stock issued in ATM offering	794	8	7,310	—	7,318
Net income	—	—	—	44,793	44,793
BALANCE, DECEMBER 31, 2023	34,052	341	127,548	140,699	268,588

The accompanying notes are an integral part of these Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Consolidation

The consolidated financial statements include the accounts of Hallador Energy Company (hereinafter, "we", "our" or "us") and our wholly owned subsidiaries Sunrise Coal, LLC ("Sunrise"), Hallador Power Company, LLC ("Hallador Power") and Hourglass Sands, LLC ("Hourglass"), as well as Sunrise and Hallador Power's wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Sunrise is engaged in the production of steam coal from mines located in western Indiana. Hallador Power is engaged in the production of coal-fired electric power generation located in Sullivan County, Indiana.

Segment Information

As the result of Hallador Power's acquisition of the Merom Generating Station one gigawatt power plant in Sullivan County, Indiana (the "Merom Power Plant") from Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier") on October 21, 2022 (the "Merom Acquisition"), as further described in Note 15, beginning in the fourth quarter of 2022, we began to strategically view and manage our operations through two reportable segments: Coal Operations and Electric Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" and primarily are comprised of unallocated corporate costs and activities, including a 50% interest in Sunrise Energy, LLC ("Sunrise Energy"), a private gas exploration company with operations in Indiana, which we account for using the equity method, and our wholly-owned subsidiary Summit Terminal LLC, a logistics transport facility located on the Ohio River.

The Coal Operations reportable segment includes currently operating mining complexes Oaktown 1 and Oaktown 2 underground mines, Prosperity surface mine, Freelandville surface mine and Carlisle wash plant. On February 23, 2024, our Sunrise Coal Division undertook an initiative designed to strengthen our financial and operational efficiency and to create significant operational savings and higher margins in our coal segment. For further information, see "Note 19 - Subsequent Events" below.

The Electric Operations reportable segment includes electric power generation facilities of the Merom Power Plant.

Reclassifications

Amounts in the prior years consolidated financial statements are reclassified whenever necessary to conform to the current year's presentation. Any reclassification adjustments had no impact on prior year total assets, liabilities, net income or shareholders' equity.

Cash and Cash Equivalents

Cash and cash equivalents include investments with maturities when purchased of three months or less. Cash balances at individual banks may exceed the federally insured limit by the Federal Deposit Insurance Corporation. The Company has not experienced any material losses in such accounts.

Accounts Receivable

The timing of revenue recognition, billings and cash collections results in accounts receivable from customers. Customers are invoiced as coal is shipped or as power is delivered or at periodic intervals in accordance with contractual terms. Invoices typically include customary adjustments for the resolution of price variability, such as coal quality thresholds. Payments are generally received within thirty days of invoicing. Historically, credit losses have been insignificant. No charges for credit losses were recognized during the years ended December 31, 2023 or 2022.

Inventory and Parts and Supplies

Inventory and parts and supplies are valued at the lower of cost or net realizable value determined using the first-in first-out method. Inventory costs include labor, supplies, operating overhead, and other related costs incurred at or on behalf of the mining location or plant, including depreciation, depletion, and amortization of equipment, buildings, mineral rights, and mine development costs.

Contract Asset - Coal Purchase Agreement

Contract Asset - Coal Purchase Agreement (as defined in Note 15) is the result of a coal purchase agreement with Hoosier whereby we purchased coal from Hoosier through May 31, 2023, at fixed prices which were below market prices at the date of entry into the agreement. This agreement was entered into as consideration in the Merom Acquisition. The asset was amortized to inventory as coal was purchased over the term of the agreement as the contract was fulfilled. During the years ended December 31, 2023 and 2022, $19.6 million and $14.7 million, respectively, were amortized, of which $30.7 million and $3.6 million, respectively, was recognized in operating expenses on the consolidated statements of operations. The Coal Purchase Agreement term was from October 21, 2022 to May 31, 2023.

Prepaid Expenses

Prepaid expenses include prepaid insurance and other prepaid balances with vendors for various services paid for in advance of use.

Advanced 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.

Mining Properties and Plant Equipment

Mining 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, mining 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.

The values of the property, plant and equipment acquired as part of the Merom Acquisition were recorded at relative fair value based on the consideration paid upon closing of the acquisition of the plant in October 2022. Other equipment is recorded at cost. 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. Most power plant equipment is depreciated using estimated useful lives ranging from four to nine years.

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. There were no long-lived asset impairments during the years ended December 31, 2023 or December 31, 2022.

Mine Development

Costs of developing new 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.

Deferred Revenue

Deferred revenue includes advance payments on electric capacity payments and prepayments on coal deliveries. The deferred revenue for each will be reversed to revenue on a monthly pro-rata basis for the capacity payments and as coal is delivered for the coal prepayments based upon the underlying contractual terms. All deferred revenue is expected to be recognized in revenue within one year.

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 (proven and probable) reserves. We use credit-adjusted risk-free discount rates ranging from 7% to 10% to discount the obligation, inflation rates anticipated during the time to reclamation, and cost estimates prepared by its engineers inclusive of market risk premiums. 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 estimated reclamation costs and changes in the estimated timing of such costs. The change in estimate for the year ended December 31, 2023, was a result of a change in timing and acreage of expected reclamation of the Merom Power Plant. In the event we are not able to perform reclamation, we have surety bonds at December 31, 2023 totaling $37.5 million to cover ARO. The undiscounted asset retirement obligation was $26.6 million and $27.0 million at December 31, 2023 and 2022, respectively.

The table below (in thousands) reflects the changes to ARO for the periods presented:

	Year Ended December 31,	
	2023	**2022**
Balance, beginning of year	$ 20,834	$ 14,125
Merom acquisition	—	7,230
Freelandville addition	—	1,631
Accretion	1,804	1,010
Change in estimate	(2,566)	—
Payments	(3,384)	(3,162)
Balance, end of year	16,688	20,834
Less current portion	(2,150)	(3,580)
Long-term balance, end of year	$ 14,538	$ 17,254

Contract Liabilities - Power Purchase Agreement and Capacity Payment Reduction

Contract Liabilities - Power Purchase Agreement and Capacity Payment Reduction (both as defined in Note 15) are the result of a power purchase agreement with Hoosier whereby Hallador Power is selling power to Hoosier through 2025 at fixed prices which were below market prices at the date the parties entered into the agreement. Hallador Power also agreed to a reduction in future capacity payments as part of the acquisition consideration. These agreements were entered into as consideration in the Merom Acquisition. The power purchase agreement liability is amortized to electric sales revenue pro-rata over the term of the agreement as the contract is fulfilled. During the years ended December 31, 2023 and 2022, amortization of the power purchase agreement contract liability totaled $70.5 million and $23.3 million, respectively. The Power Purchase Agreement term is from October 21, 2022 to December 31, 2025. The Capacity Payment Reductions occurred on May 31, 2023 and November 30, 2023 in the amount of $7.5 million each.

Interest Rate Swaps

We have historically utilized derivative instruments to manage exposures to interest rate risk on long-term debt. We enter interest rate swaps in order to achieve a mix of fixed and variable rate debt that it deems appropriate. These interest rate swaps have not been designated as hedging instruments and were accounted for as an asset or a liability in the accompanying consolidated balance sheets at their fair value. Realized and unrealized gains and losses are classified as operating activities in the accompanying consolidated statements of cash flows. As of December 31, 2023 and 2022, we were not a party to any interest rate swaps.

Commitments and Contingencies

From time to time, we are involved in legal proceedings and/or may be subject to industry rulings that could bring rise to claims in the ordinary course of business. We have concluded that the likelihood is remote that the ultimate resolution of any pending litigation or pending claims will be material or have a material adverse effect on our business, financial position, results of operations or liquidity.

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 earnings per share (“EPS”) are computed by dividing net earnings by the weighted average number of common shares outstanding for the period.

Diluted EPS attributable to common shareholders is computed by adjusting net earnings by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include shares of restricted stock units as if the units issued by us were vested and convertible debt. We apply the treasury stock method to account for the dilutive impact of its restricted stock units and the if converted method for its convertible notes. Anti-dilutive securities are excluded from diluted EPS. As a result of determining the effect of potentially dilutive securities, in certain periods, diluted net loss per share is the same as the basic net loss per share for the periods presented.

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) deferred income tax accounts, (ii) coal reserves, (iii) depreciation, depletion, and amortization, (iv) estimates related to the Merom Acquisition, (v) estimates used in our impairment analysis, and (vi) estimates used in the calculation of ARO.

Long-term Contracts

As of December 31, 2023, we are committed to supplying third-party customers up to a maximum of 9.2 million tons of coal through 2027, of which 6.2 million tons are priced. We are committed to supplying coal to Merom Power Plant up to a maximum of 10.7 million tons of coal through 2028. All committed tons to Merom are priced.

For 2023, we derived 93% of our third-party coal sales from five customers, each representing at least 10% of coal sales. At December 31, 2023, 85% of our coal operations accounts receivable was from four customers, each representing more than 10%. For the year ended December 31, 2023,100% of our electric sales and accounts receivable were with two customers.

For 2022, we derived 90% of our coal sales from five customers, each representing at least 10% of our coal sales. At December 31, 2022, 86% of our coal operations accounts receivable was from four customers, each representing more than 10%. For the year ended December 31, 2022, 100% of our electric sales and accounts receivable was with one customer.

For 2023, 100% of our delivered energy generation revenue was sold to Hoosier or the Midcontinent Independent System Operator ("MISO") wholesale market. MISO is the independent system operator managing the flow of high-voltage electricity across 15 U.S. states and the Canadian province of Manitoba. For 2023, we derived 91% of our capacity sales revenue from three customers, each representing at least 10% of capacity sales revenue. As of December 31, 2023, we are committed to supply approximately 22% of the plant’s energy generation output and approximately 32% of the plant’s capacity to Hoosier from June 1, 2023, through May 31, 2028. Additionally, as of December 31, 2023, we are committed to supply to other customers approximately 47% to 55% of the plant’s capacity during the years ending December 31, 2024, through 2026 and approximately 28% of the plant’s capacity during the years ending December 31, 2027, through 2028. For 2022, we derived 100% of our electric delivered energy generation and capacity sales revenue from Hoosier.

Stock-based Compensation

Stock-based compensation for restricted stock units 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.

Recent Accounting Pronouncements Not Yet Adopted

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures ("ASU 2023-07"). ASU 2023-07 primarily requires enhanced disclosures about significant segment expenses regularly provided to the chief operating decision maker ("CODM"), the amount and composition of other segment items, and the title and position of the CODM. ASU 2023-07 is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. We are currently evaluating the impact of adopting ASU 2023-07, but do not expect it to have a material effect on our consolidated financial statements.

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures ("ASU 2023-09"). ASU 2023-09 primarily requires enhanced disclosures to (1) disclose specific categories in the rate reconciliation, (2) disclose the amount of income taxes paid and expensed disaggregated by federal, state, and foreign taxes, with further disaggregation by individual jurisdictions if certain criteria are met, and (3) disclose income (loss) from continuing operations before income tax (benefit) disaggregated between domestic and foreign. ASU 2023-09 is effective for fiscal years beginning after December 15, 2024, with early adoption permitted. We are currently evaluating the impact of adopting ASU 2023-09, but do not expect it to have a material effect on our consolidated financial statements.

(2) INVENTORY

Inventory is valued at lower of cost or net realizable value ("NRV"). As of December 31, 2023, and 2022, coal inventory includes NRV adjustments of $2.0 million and $4.9 million, respectively.

(3) OTHER LONG-TERM ASSETS (IN THOUSANDS)

	December 31,	
	2023	2022
Advanced coal royalties	$ 5,521	$ 5,967
Other	1,540	1,618
Total other assets	$ 7,061	$ 7,585

(4) BANK DEBT

On March 25, 2022, we executed an amendment to our credit agreement with PNC Bank, National Association (in its capacity as administrative agent, "PNC"), administrative agent for its lenders under its credit agreement. The primary purpose of the amendment was to return the allowable leverage ratio and debt service coverage ratio to December 31, 2021 levels through September 30, 2022, with the debt service coverage waived for March 31, 2022.

On May 20, 2022, we executed an additional amendment to our credit agreement with PNC. The primary purpose of this amendment was to modify the allowable leverage ratio and debt service coverage ratio through June 30, 2022, to provide relief for current and anticipated covenant violations.

On August 5, 2022, we executed an additional amendment to our credit agreement with PNC. The primary purpose of this amendment was to modify the allowable leverage ratio and debt service coverage ratio through September 30, 2022, to provide relief for anticipated covenant violations.

On March 13, 2023, we executed an additional amendment to our credit agreement with PNC. The primary purpose of the amendment was to convert $35 million of the outstanding balance on the revolver into a new term loan with a maturity date of March 31, 2024, and extend the maturity date of the revolver to May 31, 2024. The amendment also reduced the total capacity under the revolver to $85 million and waived the maximum annual capital expenditure covenant for 2022 and increased the covenant for 2023 to $75 million. Subsequent to December 31, 2022, and prior to the effective date of this amendment, we had borrowed an additional $17 million under the revolver. Additionally, this amendment provided for the transition in interest rates from the London Interbank Offered Rate ("LIBOR") to the Secured Overnight Financing Rate ("SOFR") based pricing with ranges from SOFR plus 4.00% to SOFR plus 5.00%, depending on our leverage ratio.

On August 2, 2023, we executed an additional amendment to our credit agreement with PNC, which was accounted for as a debt extinguishment. The primary purpose of the amendment was to convert $65 million of the outstanding funded debt into a new term loan with a maturity of March 31, 2026, and enter into a revolver of $75 million with a maturity of July 31, 2026. The amendment increased the maximum annual capital expenditure limit to $100 million.

Prior to the March 13, 2023 amendment, bank debt was comprised of term debt ($5.5 million as of December 31, 2022) and a $120 million revolver ($79.7 million borrowed as of December 31, 2022). The term debt amortization was to conclude with the final payment of $5.5 million in March 2023. The revolver was to mature in September 2023. Under the provision of the March 13, 2023 amendment, bank debt was comprised of term debt ($35.0 million as of March 13, 2023) and an $85 million revolver ($40.2 million borrowed as of March 13, 2023). The term debt required payment of $10 million in June 2023 each quarter thereafter in 2023 and $5.0 million by March 31, 2024. Under the August 2, 2023 amendment, bank debt was comprised of term debt ($58.5 million borrowed as of December 31, 2023) and a $75 million revolver ($33.0 million borrowed as of December 31, 2023. The term debt requires payments of $6.5 million beginning April 2024 through March 2026.

Bank debt increased by $6.3 million and was reduced by $26.5 million during the years ended December 31, 2023 and 2022, respectively.

Our debt is recorded at amortized cost, which approximates fair value due to the variable interest rates in the agreement and is collateralized primarily by our assets.

Liquidity

As of December 31, 2023, we had additional borrowing capacity of $23.4 million under the revolver and total liquidity of $26.2 million. Our additional borrowing capacity is net of $18.6 million in outstanding letters of credit as of December 31, 2023 that were required to maintain surety bonds. Liquidity consists of additional borrowing capacity and cash and cash equivalents.

Fees

Unamortized bank fees and other costs incurred in connection with the initial facility and subsequent amendments totaled $2.5 million as of December 31, 2022. Additional costs incurred with the March 13, 2023 and August 2, 2023 amendments totaled $1.6 million and $4.3 million, respectively. During 2023 we recognized a loss on extinguishment of debt of $1.5 million for the write-off of unamortized loan fees related to the August 2, 2023 amendment to our credit agreement, which was accounted for as a debt extinguishment. The remaining costs were deferred and are being amortized over the term of the loan. Unamortized costs as of December 31, 2023, and December 31, 2022 were $3.6 million and $2.5 million, respectively.

Bank debt, less debt issuance costs, is presented below (in thousands):

	December 31,	
	2023	**2022**
Current bank debt	$ 26,000	$ 35,500
Less unamortized debt issuance cost	(1,562)	(2,469)
Net current portion	$ 24,438	$ 33,031
Long-term bank debt	$ 65,500	$ 49,713
Less unamortized debt issuance cost	(2,047)	—
Net long-term portion	$ 63,453	$ 49,713
Total bank debt	$ 91,500	$ 85,213
Less total unamortized debt issuance cost	(3,609)	(2,469)
Net bank debt	$ 87,891	$ 82,744

Covenants

The credit facility includes a Maximum Leverage Ratio (consolidated funded debt / trailing twelve months adjusted EBITDA), calculated as of the end of each fiscal quarter for the trailing twelve months, not to exceed 2.25 to 1.00.

As of December 31, 2023, our Leverage Ratio of 1.32 was in compliance with the requirements of the credit agreement.

Beginning December 31, 2022, the credit facility requires a Minimum Debt Service Coverage Ratio (consolidated adjusted EBITDA/annual debt service) calculated as of the end of each fiscal quarter for the trailing 12 months of 1.25 to 1.00 through the maturity of the credit facility.

As of December 31, 2023, our Debt Service Coverage Ratio of 3.30 was in compliance with the requirements of the credit agreement.

Interest Rate

The interest rate on the facility ranges from SOFR plus 4.00% to SOFR plus 5.00%, depending on our Leverage Ratio. As of December 31, 2023, we were paying SOFR plus 4.25% on the outstanding bank debt.

Future Maturities (in thousands):		
2024		26,000
2025		26,000
2026		39,500
Total	$	91,500

(5) ACCOUNTS PAYABLE AND ACCRUED LIABILITIES (IN THOUSANDS)

	December 31,			
	2023		2022	
Accounts payable	$	43,636	$	62,306
Accrued property taxes		2,987		1,917
Accrued payroll		6,575		5,933
Workers' compensation reserve		3,629		3,440
Group health insurance		2,300		2,250
Asset retirement obligation - current portion		2,150		3,580
Other		1,631		3,546
Total accounts payable and accrued liabilities	$	62,908	$	82,972

(6) REVENUE

Revenue from Contracts with Customers

We account for a contract with a customer when the parties have approved the contract and are committed to performing their respective obligations, the rights of each party are identified, payment terms are identified, the contract has commercial substance, and it is probable substantially all of the consideration will be collected. We recognize revenue when we satisfy a performance obligation by transferring control of a good or service to a customer.

Coal operations

Our coal revenue is derived from sales to customers of coal produced at its facilities. Our customers typically purchase coal directly from our mine sites where the sale occurs and where title, risk of loss, and control pass to the customer at that point. Our customers arrange for and bear the costs of transporting their coal from our mines to their plants or other specified discharge points. Our customers are typically domestic utility companies. Our coal sales agreements with our customers are fixed-priced, fixed-volume supply contracts, or include a pre-determined escalation in price for each year. Price re-opener and index provisions may allow either party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on the prevailing market price or, in some instances, require us to negotiate a new price, sometimes within specified ranges of prices. The terms of our coal sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer.

Coal sales agreements will typically contain coal quality specifications. With coal quality specifications in place, the raw coal sold by us to the customer at the delivery point must be substantially free of magnetic material and other foreign material impurities and crushed to a maximum size as set forth in the respective coal sales agreement. Price adjustments are made and billed in the month the coal sale was recognized based on quality standards that are specified in the coal sales agreement, such as British thermal unit ("Btu") factor, moisture, ash, and sulfur content, and can result in either increases or decreases in the value of the coal shipped.

Electric operations

We concluded that for a Power Purchase Agreement ("PPA") that is not determined to be a lease or derivative, the definition of a contract and the criteria in ASC 606, Revenue from Contracts with Customers ("ASC 606"), is met at the time a PPA is executed by the parties, as this is the point at which enforceable rights and obligations are established. Accordingly, we concluded that a PPA that is not determined to be a lease or derivative constitutes a valid contract under ASC 606.

We recognize revenue daily, based on an output method of capacity made available as part of any stand-ready obligations for contract capacity performance obligations and daily, based on an output method of MWh of electricity delivered.

For the delivered energy performance obligation in the PPA with Hoosier, we recognize revenue daily for actual delivered electricity plus the amortization of the contract liability as a result of the Asset Purchase Agreement with Hoosier. For the delivered energy to all other customers, we recognize revenue daily for the actual delivered electricity.

Disaggregation of Revenue

Revenue is disaggregated by primary geographic markets for our coal operations and by revenue source for our electric operations, as we believe this best depicts how the nature, amount, timing, and uncertainty of its revenue and cash flows are affected by economic factors.

Coal operations

For the years ended December 31, 2023 and 2022, 33% and 74%, respectively, of our coal revenue was sold to customers in the State of Indiana with the remainder sold to customers in Florida, North Carolina, Georgia, and Alabama.

Electric operations

For the year ended December 31, 2023, electric sales revenue from delivered energy generation and capacity sales revenue was $211.8 million and $56.1 million, respectively. For the year ended December 31, 2022, electric sales revenue from delivered energy generation and capacity sales revenue was $53.9 million and $12.3 million, respectively.

Performance Obligations

Coal operations

A performance obligation is a promise in a contract with a customer to provide distinct goods or services. Performance obligations are the unit of account for purposes of applying the revenue recognition standard and therefore determine when and how revenue is recognized. In most of our coal contracts, the customer contracts with us to provide coal that meets certain quality criteria. We consider each ton of coal a separate performance obligation and allocate the transaction price based on the base price per the contract, increased or decreased for quality adjustments.

We recognize revenue at a point in time as the customer does not have control over the asset at any point during the fulfillment of the contract. For substantially all of our customers, this is supported by the fact that title and risk of loss transfer to the customer upon loading of the truck or railcar at the mine. This is also the point at which physical possession of the coal transfers to the customer, as well as the right to receive substantially all benefits and the risk of loss in ownership of the coal.

We have remaining coal sales performance obligations relating to fixed priced contracts to third-party customers of approximately $324 million, which represent the average fixed prices on our committed contracts as of December 31, 2023. We expect to recognize approximately 55% of this coal sales revenue in 2024, with the remainder recognized through 2027.

We have remaining performance obligations relating to coal sales contracts with price reopeners of approximately $155 million, which represents our estimate of the expected re-opener price on committed contracts as of December 31, 2023. We expect to recognize all of this coal sales revenue beginning in 2024 through 2027.

The coal tons used to determine the remaining performance obligations are subject to adjustment in instances of force majeure and exercise of customer options to either take additional tons or reduce tonnage if such option exists in the customer contract.

Electric operations

We concluded that each megawatt hour ("MWh") of delivered energy is capable of being distinct as a customer could benefit from each on its own by using/consuming it as a part of its operations. We also concluded that the stand-ready obligation to be available to provide electricity is capable of being distinct as each unit of capacity provides an economic benefit to the holder and could be sold by the customer.

In accordance with the APA, as defined in Note 15. Merom Acquisition, with Hoosier, Hallador Power shall sell, and Hoosier shall buy, at least 70% of the delivered energy quantities through 2025 at the contract price, which is $34.00 per MWh. We have remaining delivered energy obligations to Hoosier totaling $115.6 million through 2025 as of December 31, 2023. The agreement was amended August 31, 2023 to extend through 2028 with additional obligations to Hoosier of $186.6 million as of December 31, 2023.

In addition to delivered energy, under the APA, Hallador Power shall provide a stand-ready obligation to provide electricity, also known as contract capacity. The contract capacity that Hallador Power shall provide to Hoosier is 917 megawatts ("MW") for contract year one, and 300 MW for contract years two to four. Hoosier shall pay Hallador Power the capacity price of $5.80 per kilowatt month for the contract capacity. We have remaining capacity obligations to Hoosier through 2025 totaling $41.6 million as of December 31, 2023. The agreement was amended August 31, 2023 to extend through 2028 with additional capacity obligation to Hoosier of $60.9 million as of December 31, 2023.

We also have capacity obligations outside of the APA to customers through 2028 totaling $144.6 million as of December 31, 2023. The Company has $23.1 million of deferred revenue as of December 31, 2023, related to these obligations.

Contract Balances

Under ASC 606, the timing of when a performance obligation is satisfied can affect the presentation of accounts receivable, contract assets, and contract liabilities. The main distinction between accounts receivable and contract assets is whether consideration is conditional on something other than the passage of time. A receivable is an entity's right to consideration that is unconditional.

Under the typical payment terms of our contracts with customers, the customer pays us a base price for the coal, increased or decreased for any quality adjustments, electricity, or capacity. Amounts billed and due are recorded as trade accounts receivable and included in accounts receivable in our consolidated balance sheets. As of December 31, 2023, accounts receivable for coal sales billed to customers was $14.3 million. We do not currently have any other contracts in place where it would transfer coal, electricity or capacity in advance of knowing the final price, and thus do not have any other contract assets recorded. Contract liabilities also arise when consideration is received in advance of performance.

(7) INCOME TAXES

Our income tax is different than the expected amount computed using the applicable federal statutory income tax rate of 21%. The reasons for and effects of such differences for the years ended December 31 are below (in thousands):

	2023	2022
Expected amount	$ 10,344	$ 4,171
State income taxes, net of federal benefit	1,246	391
Percentage depletion	(3,348)	(2,081)
Change in valuation allowance	(3,681)	(970)
Stock-based compensation	(844)	—
Return to provision adjustments	159	153
Other	589	92
Total income tax expense	$ 4,465	$ 1,756

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

	2023	2022
Deferred tax assets:		
Net operating loss	$ 20,029	$ 26,570
Power contracts	23,302	34,233
Compensation	2,287	1,344
Accrued liabilities	570	556
Other	2,016	471
Total deferred tax assets	48,204	63,174
Valuation allowance	—	(3,681)
Deferred tax assets, net of valuation allowance	48,204	59,493
Deferred tax liabilities:		
Coal properties	(25,764)	(27,700)
Power properties	(31,126)	(35,702)
Investment partnerships	(549)	(494)
Other	—	(203)
Total deferred tax liabilities	(57,439)	(64,099)
Net deferred tax liability	$ (9,235)	$ (4,606)

Our effective tax rate ("ETR") for 2023 and 2022 was approximately 9%. The tax rate for the years ended December 31, 2023 and 2022 are not predictive of future tax rates. Our ETR differs from the statutory rate due to statutory depletion in excess of tax basis, return to provision adjustments, stock-based compensation and changes in the valuation allowance. The deduction for statutory depletion does not necessarily change proportionately to changes in income before income taxes.

We recognize deferred tax assets to the extent that we believe that these assets are more likely than not to be realized. In making such a determination, we consider all available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning strategies, and results of recent operations. Due to historical cumulative earnings over the prior three years as well as projected earnings into the future, we believe that it is more likely than not that the benefit from certain federal and state deferred tax assets will be realized. As such, we released the valuation allowance as of December 31, 2023.

The federal NOLs generated in pre-2018 years and remaining of $13.4 million can offset 100% of future years' taxable income. The federal NOLs generated in post 2017 years of $60.7 million can offset 80% of future years' taxable income. The pre-2018 federal NOLs will expire in varying amounts from 2035 to 2037 if they are not utilized. Indiana NOLs have a 20-year carryforward period and will expire in the years 2034 to 2041 if they are not utilized.

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 be 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 its consolidated financial position. While not material, we record any penalties and interest as general and administrative expense. Tax returns filed with the Internal Revenue Service and state entities generally remain subject to examination for three years after filing.

(8) STOCK COMPENSATION PLANS

Restricted Stock Units (RSUs)

The table below shows the number of RSUs available for issuance at December 31, 2023:

Total authorized RSUs in Plan approved by shareholders	4,850,000
Stock issued out of the Plan from vested grants	(3,540,178)
Non-vested grants	(858,363)
RSUs available for future issuance	451,459

Non-vested grants at December 31, 2021	183,000
Granted – weighted average share price on grant date was $6.74	881,437
Vested	—
Forfeited	(7,500)
Non-vested grants at December 31, 2022	1,056,937
Granted – weighted average share price on grant date was $9.30	312,147
Vested	(472,721)
Forfeited	(38,000)
Non-vested grants at December 31, 2023	858,363

RSU Vesting Schedule

Vesting Year	RSUs Vesting
2024	319,419
2025	538,944

Shares vested in 2023 had a value of $5.0 million based on the share price of $10.69 on their vesting dates. 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 $7.2 million based on the March 8, 2024 closing stock price of $8.39.

For the years ended December 31, 2023 and 2022, stock-based compensation was $3.6 million and $1.3 million, respectively.

As of December 31, 2023, unrecognized stock compensation expense was $4.1 million, and we had 451,459 RSUs available for future issuance. RSUs are not allocated earnings and losses as they are considered non-participating securities.

Stock Options

We have no stock options outstanding.

(9) EMPLOYEE BENEFITS

Our employee benefit expenses for the years ended December 31 are below (in thousands):

	2023	2022
Health benefits, including premiums	$ 18,483	$ 14,607
401(k) matching	2,910	2,549
Deferred bonus plan	687	809
Total	$ 22,080	$ 17,965

Of the amounts in the above table, $21.5 million and $17.4 million are recorded in operating expenses in the consolidated statements of operations for the years ended December 31, 2023 and 2022, respectively, with the remainder in general and administrative.

Our mine employees are also covered by workers' compensation and such costs were approximately $4.9 million for 2023 and 2022, and are recorded in operating expenses in the consolidated statements of operations. 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. We are partially self-insured for such claims, however, its operations are protected from these perils through stop-loss insurance policies. Our maximum annual exposure is limited to $1.0 million per occurrence with a $4.0 million aggregate deductible.

(10) LEASES

We determine if an arrangement is an operating or finance lease at the inception of each contract. If the contract is classified as an operating lease, we record a right-of-use ("ROU") asset and corresponding liability reflecting the total remaining present value of fixed lease payments over the expected term of the lease agreement. The expected term of the lease may include options to extend or terminate the lease when it is reasonably certain that we will exercise that option. If our lease does not provide an implicit rate in the contract, we use our incremental borrowing rate when calculating the present value. We have 2 operating leases for office space and processing facilities with remaining lease terms ranging from less than one year to approximately five years. As most of the leases do not provide an implicit rate, we calculate the ROU assets and lease liabilities using our secured incremental borrowing rate at the lease commencement date. At December 31, 2023 and 2022, respectively, we had approximately $0.7 and $0.2 million of ROU operating lease assets recorded within buildings and equipment on the consolidated balance sheets. Operating lease expense associated with ROU assets is recognized on a monthly basis over the lease term in operating costs on the consolidated statements of operation.

We entered into three finance leases during 2023, which are accounted for as failed sale-leaseback transactions. Finance lease assets are included in finance lease right-of-use assets on the consolidated balance sheets and the associated finance lease liabilities are reflected within current portion of lease financing and long-term lease financing on the consolidated balance sheets as applicable. Depreciation on our finance lease assets was $2.3 million for the year ended December 31, 2023. Imputed interest expense on our lease liabilities was $0.1 million for the year ended December 31, 2023. We deferred financing fees of $0.1 million in connection with entry into the finance leases. These deferred financing fees will be amortized on a straight-line basis over the term of the finance leases. For the year ended December 31, 2023, the amortization of finance lease deferred financing fees was immaterial.

Information related to leases was as follows as of December 31 (in thousands):

	December 31,	
	2023	2022
Operating lease information:		
Operating cash outflows from operating leases	$ 208	$ 218
Weighted average remaining lease term in years	8.50	1.30
Weighted average discount rate	9.5%	6.0%
Finance lease information:		
Financing cash outflows from finance leases	$ —	$ —
Proceeds from sale and leaseback arrangement	11,082	—
Weighted average remaining lease term in years	3.00	—
Weighted average discount rate	8.5%	—%

We recognized the following costs related to our leases in our consolidated balance sheets:

	Classification on Consolidated Balance Sheets	December 31, 2023	December 31, 2022
		(in thousands)	
Operating lease assets	Buildings and equipment	$ 712	$ 230
Operating lease liabilities:			
Current operating lease liabilities	Accounts payable and accrued liabilities	$ 58	$ 173
Non-current operating lease liabilities	Other long-term liabilities	$ 654	$ 57
Total operating lease liabilities		$ 712	$ 230
Finance lease assets	Finance lease right-of-use assets	$ 12,346	$ —
Finance lease liabilities:			
Current finance lease liabilities	Current portion of lease financing	$ 3,933	$ —
Non-current finance lease liabilities	Long-term lease financing	$ 8,157	$ —
Total finance lease liabilities		$ 12,090	$ —

Future minimum lease payments under non-cancellable leases as of December 31, 2023, were as follows:

Year	Operating Leases	Finance Leases
	(in thousands)	
2024	$ 58	$ 4,947
2025	118	4,645
2026	122	4,333
2027	125	—
2028	129	—
Thereafter	483	—
Total minimum lease payments	$ 1,035	$ 13,925
Less imputed interest and deferred finance fees	(323)	(1,835)
Total lease liability	$ 712	$ 12,090

(11) SELF INSURANCE

We self-insure non-leased underground mining equipment. Such equipment is allocated among seven mining units dispersed over 11 miles. The historical cost of such equipment was approximately $262 million and $280 million as of December 31, 2023 and 2022, respectively.

Restricted cash of $4.3 million and $3.4 million as of December 31, 2023 and 2022, respectively, represents cash held and controlled by a third party and is restricted for future workers' compensation claim payments.

(12) NET INCOME PER SHARE

The following table (in thousands, except per share amounts) sets forth the computation of basic earnings per share for the periods presented:

	Year Ended December 31, 2023	Year Ended December 31, 2022
Basic earnings per common share:		
Net income - basic	$ 44,793	$ 18,105
Weighted average shares outstanding - basic	33,133	32,043
Basic earnings per common share	$ 1.35	$ 0.57

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

	Year Ended December 31, 2023	Year Ended December 31, 2022
Diluted earnings per common share:		
Net income - basic	$ 44,793	$ 18,105
Add: Convertible Notes interest expense, net of tax	1,201	527
Net income - diluted	$ 45,994	$ 18,632
Weighted average shares outstanding - basic	33,133	32,043
Add: Dilutive effects of if converted Convertible Notes	3,164	1,398
Add: Dilutive effects of Restricted Stock Units	530	208
Weighted average shares outstanding - diluted	36,827	33,649
Diluted net earnings per share	$ 1.25	$ 0.55

(13) 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. We have no Level 1 instruments.

Level 2: Quoted prices in markets that are not active, or inputs that 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). ARO liabilities use Level 3 non-recurring fair value measures as further discussed in Note 1. Lastly, Level 3 fair value measurements were also used in the determination of the fair values of assets acquired, liabilities assumed, and considerations exchanged as part of the Merom Acquisition.

(14) EQUITY METHOD INVESTMENTS

Sunrise Energy, LLC

We own a 50% interest in Sunrise Energy, 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, natural gas, and coal-bed methane gas reserves on or near our underground coal reserves. The carrying value of the investment included in the consolidated balance sheets as of December 31, 2023 and 2022 was $2.8 million and $4.0 million, respectively.

(15) MEROM ACQUISITION

On February 14, 2022, Hallador Power signed an Asset Purchase Agreement (“APA”), with Hoosier, a rural electric membership corporation organized and existing under the laws of the state of Indiana.

Under the APA, Hallador Power acquired the Merom power plant, along with: equipment and machinery in the power plant; materials inventory; a coal purchase agreement; a coal combustion certified coal ash landfill, certain generation interconnection agreements, and coal inventory (collectively, the “Acquired Assets”). Additionally, contemporaneous with entering into the APA, Hallador Power entered into three other agreements with Hoosier comprised of (1) a Power Purchase Agreement (the “PPA”), (2) a Coal Supply Purchase Agreement (the “Coal Purchase Agreement”), and (3) a Closing Side Letter agreeing to a reduction in future capacity payments of $15.0 million (“Capacity Payment Reduction”). The purchase price for the Acquired Assets also consisted of the assumption of the power plant’s closure and post-closure remediation, valued at approximately $7.2 million; no cash was paid by Hallador Power to Hoosier to effectuate the APA other than payments totaling approximately $17.0 million for coal inventory on hand, with an initial payment of $5.4 million and subsequent periodic payments over time, subject to post-close adjustments based on actual on-site inventories. The acquisition closed on October 21, 2022.

The acquisition was accounted for as an asset acquisition under ASC Topic 805-50, *Business Combinations* as substantially all of the fair value of the gross assets acquired are concentrated in a group of similar identifiable assets. As such, the total purchase consideration (which includes $2.9 million of transaction costs) is allocated to the assets acquired on a relative fair value basis.

The following table summarizes the final relative fair value allocation of assets acquired and liabilities assumed and incurred as of the Merom Acquisition date.

		(in thousands)
Consideration:		
Direct transaction costs	$	2,855
Contract liability - PPA		184,500
Contract liability - Capacity payment reduction		11,000
Contract asset - Coal purchase agreement		(34,300)
Coal inventory purchased		5,400
Deferred coal inventory payment		11,600
Total consideration	$	181,055
Relative fair value of assets acquired:		
Plant	$	165,816
Materials and supplies		12,009
Coal inventory		10,460
Amount attributable to assets acquired	$	188,285
Fair value of liabilities assumed:		
Asset retirement obligations	$	7,230
Amount attributable to liabilities assumed	$	7,230

(16) CONVERTIBLE NOTES

On May 2, 2022, and May 20, 2022, we issued senior unsecured convertible notes (the "Notes") to five parties, in the aggregate principal amount of $10 million, with $9 million being issued to related parties affiliated with independent members of our board of directors and the remainder to a non-affiliated party. The Notes were scheduled to mature on December 29, 2028, and accrue interest at 8% per annum, with interest payable on the date of maturity. Pursuant to the terms of the Notes, the holders of the Notes may convert the entire principal balance and all accrued and unpaid interest then outstanding during the period beginning June 1, 2022, and ending on May 31, 2027, into shares of the Company's common stock at a conversion price the greater of (i) $3.33 and (ii) the 30-day trailing volume-weighted average sales price for the common stock on the Nasdaq Capital Market ending on and including the date on which this Note is converted. At any time on or after June 1, 2025, we may, at our option and upon 30 days' written notice provided to the holders, elect to redeem the Notes (in whole and not in part) and the holders shall be obligated to surrender the Notes, at a redemption price equal to 100% of the outstanding principal balance, together with any accrued but unpaid interest thereon to the redemption date. After receipt of such redemption notice from us, the holder may, at its option, elect to convert the principal balance and accrued interest into the Company's common stock by giving written notice of such election to us no later than 5 days prior to the date fixed for redemption.

In June 2022, the four holders of the $9 million related party notes converted them into 1,965,841 shares of common stock of the Company and the one holder of the $1 million Notes converted it into 231,697 shares of common stock pursuant to the terms of the Notes and their related agreements.

On July 29, 2022, we issued an additional $5 million senior unsecured convertible note to a related party affiliated with an independent member of our board of directors. The Note carries an interest rate of 8% per annum with a maturity date of December 29, 2028. For the period August 18, 2022 through August 17, 2024, the holder has the option to convert the Note into shares of our common stock at a conversion price of $6.254. Beginning August 18, 2025, we may elect to redeem the Note and the holder shall be obligated to surrender the note at 100% of the outstanding principal balance together with any accrued unpaid interest. Upon receipt of the redemption notice from us, the holder may elect to convert the principal balance and accrued interest into the Company's common stock.

On August 8, 2022, we issued an additional $4 million of senior unsecured convertible notes to related parties affiliated with independent members of our board of directors. The Notes carry an interest rate of 8% per annum with a maturity date of December 29, 2028. For the period August 18, 2022 through August 17, 2024, the holder has the option to convert the Notes into shares of our common stock at a conversion price of $6.254. Beginning August 8, 2025, we may elect to redeem the Notes and the holder shall be obligated to surrender the Notes at 100% of the outstanding principal balance together with any accrued unpaid interest. Upon receipt of the redemption notice from us, the holder may elect to convert the principal balance and accrued interest into the Company's common stock.

On August 12, 2022, we issued an additional $10 million senior unsecured convertible note to an unrelated party. The Note carries an interest rate of 8% per annum with a maturity date of December 31, 2026. For the period August 18, 2022, through the maturity date, the holder has the option to convert the Note into shares of our common stock at a conversion price of $6.15. Beginning August 12, 2025, we may elect to redeem the Note and the holder shall be obligated to surrender the Note at 100% of the outstanding principal balance together with any accrued unpaid interest. Upon receipt of the redemption notice from us, the holder may elect to convert the principal balance and accrued interest into the Company's common stock.

The funds received from the issuance of the various Notes described above in this Note 16 were used to provide additional working capital to the Company. The conversion price and number of shares of our common stock issuable upon conversion of the above notes are subject to adjustment from time to time for any subdivision or consolidation of our shares of common stock and other standard dilutive events.

(17) AT MARKET AGREEMENT

On December 18, 2023, we entered into an At Market Issuance Sales Agreement (the "Sales Agreement") with B. Riley Securities, Inc. (the "Agent"), pursuant to which we may issue and sell, from time to time, shares (the "Shares") of our common stock, par value $0.01 per share (the "Common Stock"), with aggregate gross proceeds of up to $50 million through an "at-the-market" equity offering program under which the Agent will act as sales agent (the "ATM Program"). Under the Sales Agreement, each of us and the Agent have the right, by giving five (5) days' notice, to terminate the Sales Agreement in its sole discretion. The Agent may also terminate the Agreement, by notice to us, upon the occurrence of certain events described in the Sales Agreement.

During December 2023, we issued 794,000 shares of Common Stock under the ATM Program for net proceeds of $7.3 million. For the period January 1, 2024, to March 14, 2024, we issued 710,623 shares of Common Stock under the ATM Program for net proceeds of $6.6 million.

(18) SEGMENTS OF BUSINESS

At December 31, 2023, our operations are divided into two primary reportable segments, the Coal Operations and Electric Operations segments. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other and Eliminations" and primarily are comprised of unallocated corporate costs and activities, including a 50% interest in Sunrise Energy, which is accounted for using the equity method and our wholly-owned subsidiary Summit Terminal LLC, a logistics transport facility located on the Ohio River.

Year Ended December 31, (in thousands)		2023		2022
Operating Revenues				
Coal Operations	$	435,425	$	293,344
Electric Operations	$	268,341	$	66,316
Corporate and Other and Eliminations	$	(69,286)	$	2,331
Consolidated Operating Revenues	$	634,480	$	361,991
Income (Loss) from Operations				
Coal Operations	$	63,600	$	3,736
Electric Operations	$	12,552	$	31,505
Corporate and Other and Eliminations	$	(11,140)	$	(4,811)
Consolidated Income (Loss) from Operations	$	65,012	$	30,430
Depreciation, Depletion and Amortization				
Coal Operations	$	48,365	$	43,612
Electric Operations	$	18,739	$	3,117
Corporate and Other and Eliminations	$	107	$	146
Consolidated Depreciation, Depletion and Amortization	$	67,211	$	46,875
Assets				
Coal Operations	$	376,387	$	376,228
Electric Operations	$	208,331	$	266,730
Corporate and Other and Eliminations	$	5,062	$	(12,404)
Consolidated Assets	$	589,780	$	630,554
Capital Expenditures				
Coal Operations	$	56,521	$	50,367
Electric Operations	$	18,831	$	3,653
Corporate and Other and Eliminations	$	-	$	-
Consolidated Capital Expenditures	$	75,352	$	54,020

(19) SUBSEQUENT EVENTS

On February 23, 2024, our Coal Operations Segment undertook an initiative designed to strengthen our financial and operational efficiency and to create significant operational savings and higher margins in our coal segment. This step will advance our transition from a company primarily focused on coal production to a more resilient and diversified vertically integrated IPP. As part of this initiative, we idled production at our higher cost Prosperity Mine, and substantially idled production at Freelandville Mine with minimal production. We also focused our seven units of underground equipment on four units of our lowest cost production at our Oaktown Mine. Increasing the run time of these four lower cost units from five and a half days per week to seven days per week is intended to further improve the overall cost structure of the coal segment. As part of the initiative, the Company reduced its workforce by approximately 110 employees.

In the first quarter of 2024, Hallador borrowed $5 million from certain members of the Company's Board of Directors. The notes are unsecured, mature in February 2025 and accrue interest at 12% annually, with interest to be paid quarterly beginning on May 31, 2024.

In February 2024, the Company elected to pay the semi-annual interest due on the $19 million senior unsecured convertible notes with common stock as allowed in the note agreements. The amount of stock issued for the interest payments was 122,600 shares.

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

None.

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.

Management's Annual Report on 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, 2023. Based on that evaluation, our management concluded that our ICFR was effective at December 31, 2023.

Grant Thornton LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2023, as stated in their report that is included herein.

There were no significant changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2023, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Hallador Energy Company

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Hallador Energy Company (a Colorado corporation) and subsidiaries (the "Company") as of December 31, 2023, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2023, and our report dated March 14, 2024 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting ("Management's Report"). Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and limitations of internal control over financial reporting

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.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 14, 2024

ITEM 9B. OTHER INFORMATION

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

None.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Items 10 through 14 of Part III of this Report is incorporated by reference from our definitive proxy statement, which is to be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2023.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

See Item 8 for an index of our financial statements.

Our exhibit index is as follows:

1.1	At Market Issuance Sales Agreement, dated December 18, 2023, between Hallador Energy Company and B. Riley Securities, Inc. (17)
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 (2)
4.1	Description of Securities (3)
10.2	Third Amended and Restated Credit Agreement dated May 21, 2018 (5)
10.3	Second Amendment to the Third Amended and Restated Credit Agreement and Waiver dated September 30, 2019 (6)
10.4	Third Amendment to the Third Amended and Restated Credit Agreement and Waiver (7)
10.5	Sixth Amendment to the Third Amended and Restated Credit Agreement dated March 25, 2022 (10)
10.	Seventh Amendment to the Third Amended and Restated Credit Agreement dated May 20, 2022 (12)
10.6	Eighth Amendment to the Third Amended and Restated Credit Agreement dated August 5, 2022 (14)
10.7	Ninth Amendment to the Third Amended and Restated Credit Agreement dated September 28, 2022 (16)
10.8	Tenth Amendment to the Third Amended and Restated Credit Agreement dated March 13, 2023 (19)
10.9	Amendment and Restated Loan Agreement dated August 2, 2023 (20)
10.10	Amended and Restated Hallador Energy Company 2008 Restricted Stock Unit Plan (8)
10.11	Form of Hallador Energy Company Restricted Stock Unit Issuance Agreement (8)
10.13	2022 Executive Officer Compensation Plan**(17)
10.14	Asset and Purchase Agreement dated February 14, 2022 (9)
14.1	Code of Ethics for Senior Officers (18)
21.1	List of Subsidiaries*
23.1	Consent of Grant Thornton LLP*
23.2	Consent of John T. Boyd Company*
31.1	SOX 302 Certification - President and CEO*
31.2	SOX 302 Certifications - CFO*
32	SOX 906 Certification*
95	Mine Safety Disclosure*
97.1	Hallador Energy Company Policy for the Recovery of Erroneously Awarded Compensation*
99.1	Technical Report Summary (Coal Resources and Coal Reserves, Oaktown Mining Complex), dated October 2023(22)
99.2	Letter from Boyd and Company, dated January 29, 2024*

101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Schema Document
101.CAL*	Inline XBRL Calculation Linkbase Document
101.LAB*	Inline XBRL Labels Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
101.DEF*	Inline XBRL Definition Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL and contained in Exhibit 101)

(1) IBR to Form 8-K dated December 31, 2009
(2) IBR to Form 10-K/A amendment 1, filed June 12, 2020
(3) IBR to Form 10-K filed March 9, 2020
(4) IBR to Form 10-Q filed August 6, 2018
(5) IBR to Form 10-Q filed November 4, 2019
(6) IBR to Form 10-Q filed May 11, 2020
(7) IBR to Form DEF 14A dated April 11, 2017
(8) IBR to Form 8-K/A filed February 18, 2022
(9) IBR to Form 10-K filed March 28, 2022
(10) IBR to Form 10-Q filed May 23, 2022
(11) IBR to Form 8-K filed August 11, 2022
(12) IBR to Form 8-K filed October 4, 2022
(13) IBR to Form 10-Q filed November 14, 2022
(14) IBR to Form 10KSB dated April 14, 2006
(15) IBR to Form 10-K filed on March 16, 2023
(16) IBR to Form 10-Q filed on August 7, 2023
(17) IBR to Form 8-K filed on December 18, 2023
(18) IBR to Form 10-K/A amendment 1, filed November 1, 2023
* 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 14, 2024

/s/LAWRENCE D. MARTIN
Lawrence D. Martin, CFO (Principal Financial Officer and Principal Accounting Officer)

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 14, 2024
/s/BRYAN LAWRENCE Bryan Lawrence	Director	March 14, 2024
/s/BRENT BILSLAND Brent Bilsland	Board Chairman, President and CEO	March 14, 2024
/s/DAVID J. LUBAR David J. Lubar	Director	March 14, 2024

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Date of Report (Date of earliest event reported): March 28, 2024

Hallador Energy Company
(Exact name of registrant as specified in its charter)

Colorado	001-34743	84-1014610
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1183 East Canvasback Drive, Terre Haute, Indiana 47802
(Address, including zip code, of principal executive offices)

Registrant's telephone number, including area code: (812) 299-2800

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Shares, $.01 par value	HNRG	Nasdaq

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

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

Item 8.01 Other Events.

Hallador Energy Company (the “Company”) is filing this Current Report on Form 8-K to correct a typographical error in its earnings release furnished by the Company with its Current Report on Form 8-K filed with the Securities and Exchange Commission (“SEC”) on March 14, 2024, and in its Annual Report on Form 10-K filed with the SEC on March 14, 2024 (the “Form 10-K”). In the press release, the row in the table on the second page reading “Average cost per ton of coal sold was $33.67 for the year ended December 31, 2023 ($26.98 after eliminating for intercompany sales to Merom)” (which incorrectly copied the “average cost per MWh sold” data that appears below in the same table) is hereby replaced with “Average cost per ton of coal sold was $44.94 for the year ended December 31, 2023 ($52.76 after eliminating for intercompany sales to Merom)”. The same error appears in the table included on page 31 of the Form 10-K and is similarly corrected. No other figures in the press release or Form 10-K are impacted.

Item 9.01 – Financial Statements and Exhibits.

(d) Exhibits

104 - Cover Page Interactive Data File (embedded within the Inline XBRL document)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

March 28, 2024	By:	/s/LAWRENCE D. MARTIN Lawrence D. Martin Chief Financial Officer